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May 15, 2007

The Honorable Bruce Patterson
State Senator
State Capitol
P.O. Box 30036
Lansing, MI 48909

Dear Senator Patterson:

Enclosed are responses to the written questions submitted by members of the Senate Energy Policy and Public Utilities Committee in connection with my February 22 testimony on the 21st Century Energy Plan.

If you or members of the Committee have questions, please do not hesitate to contact me.

Very truly yours,

J. Peter Lark, Chairman
Michigan Public Service Commission

c: Members, Senate Energy Policy and Public Utilities Committee

Questions Regarding the 21st Century Energy Plan from the Senate Energy Policy & Public Utilities Committee

Questions from Senator Patterson

1. **What if the economy takes a serious downturn and it becomes apparent during construction that a new plant is not needed? What happens? May the utility go forth and build an unneeded plant? Would the utility feel compelled to proceed, as completion is the only way for the utility to recoup its investment, and the need cannot be challenged?**

   The Plan's recommendations have addressed this issue. The utility will be allowed to seek a certificate of need for construction of a new plant. If the utility can demonstrate the need for a new plant through a comprehensive Integrated Resource Plan (IRP) filing, and if a certificate is issued, the issue of need will be resolved. Because the Plan's recommendations are so conservative, we have not proposed measures to prematurely terminate plant construction.

   The issue of a plant's need after construction has already begun would likely only be relevant for baseload plants that require six years or more to complete. The Plan, however, is very conservative in its baseload recommendations; proposing one baseload plant no later than 2015 and another baseload plant if needed, on a staggered basis. Since the Plan anticipates that nearly 3,500 MW of baseload generation will be retired between 2015 and 2025, even if the economy takes a serious downturn or continues its weak performance, the Plan's recommendations will assure that unneeded baseload plant will not be built.

   As an additional check on the need for the plant, modeling for the Plan used three demand growth rates: a base growth case, a low growth sensitivity, and a high growth sensitivity. Even in the low growth sensitivity with a .3% annual growth rate over the first 10 years of the planning period, a base load unit was added in 2015. Therefore, I am confident that the Plan's recommendations will not result in the construction of unneeded generating plant.

   Finally, new base load plants are significantly more efficient than existing plants, which means that the new plants will be dispatched to serve energy needs before most existing plants. Even if the capacity from a new base load unit is not needed for a few years, the plant's energy production will be useful, especially in the Midwest wholesale markets.

2. **During the up front approval process how does the Utility or the MPSC make an informed decision as to which infrastructure approach, transmission or generation, is appropriate from a cost point of view if the cost of the generation is not even known until after the MPSC's need decision has been made?**

Considerable thought was devoted to assuring a balanced appraisal of traditional generation, non-traditional generation, transmission, load management, and energy efficiency options in the planning process. The Plan, itself, evaluated generation, transmission, and other resource options simultaneously using the same set of assumptions and data, and I would recommend following this IRP format in the future.

The comparison of in-state generation to expanded transmission, combined with out-of-state generation, was investigated thoroughly by the Plan. This analysis relied on available data to estimate construction costs for generation plants, transmission lines, and external market prices.

For the Plan, participants relied on generation plant construction cost estimates from the U.S. Department of Energy's Energy Information Agency, other studies available from national sources, the costs of units now under construction in this region of the country, and data from vendors. Likewise, the Plan participants needed to estimate the costs of transmission, which can be difficult to do as well. Based upon data supplied by ITC, the Plan included an expansion of transmission based on an $800 million, 2,500 MW, proposed direct current line. Finally, as a transmission line merely provides a method for accessing power supplies, planners must also estimate the cost of that external power supply over the entire planning horizon. All these studies and analyses were performed simultaneously, so the comparison to in-state generation with transmission improvements along with access to power outside of Michigan could be made at one point in time.

Since the recommendation for a certificate of need is a contested case format, interested parties will be allowed to file comments, and it is expected that those comments will include proposed alternatives such as transmission lines to import power from external sources. Transmission companies and regional transmission companies (RTOs) are continually planning and evaluating transmission upgrades and additions through their regional transmission expansion planning activities. Generation alternatives that may be planned do not go through a similar regional planning process and the IRP filing with a certificate of need will allow those generation alternatives to be evaluated in concert with the transmission expansion planning activities that are undertaken by the RTO. The overarching goal of an IRP filing and certificate of need is to ensure that all possible alternatives have been evaluated on a comparable basis and informed decisions are made to serve Michigan in the best way possible.

3. **With regards to how the MPSC would judge between constructing new generation and increasing transmission capacity there is a more fundamental question: If the process is to begin the analysis with a utility IRP proposal, won't transmission solutions procedurally always be playing catch up with generation solutions?**

No, as noted in the response to question 2, transmission options are evaluated simultaneously with generation options in the IRP process. Participants spent considerable time and effort to assure that all resource options were included in the modeling phase of the Plan, and we expect that to be the case in the future as well. Any certificate of need application would need to begin with this comprehensive IRP format, in which interested parties could participate. Michigan has independent transmission companies that have been and are aggressively proposing transmission expansion projects. The Michigan transmission companies also actively participate in the Midwest Independent System Operator's (MISO) regional planning process, in which transmission projects are evaluated by MISO. I am confident that participation from these parties, other intervenors, and Commission staff will assure that transmission options are considered on the same basis as in-state generation options.

4. **If a <u>Utility</u> Integrated Resource Plan is used to make the base case at the MPSC as to whether new generation or transmission should be used, won't the initial case be biased in favor of generation solutions? After all utilities make significantly more money if they build generation. More importantly won't utilities be biased against transmission solutions altogether if they are completely out of the transmission business and make NO money if a transmission solution is adopted?**

Although a utility may have a slanted view toward generation, a transmission company may have a slanted view toward transmission, a wind developer may have a slanted view toward renewables, and a group of industrial customers may have their own unique views, the Plan's recommendations for IRPs and certificates of need will serve to balance the views of individuals to develop informed decisions for Michigan load going forward.

The Plan calls for legislation that will give the Commission the authority to set filing standards for the IRP, including the standards needed to weigh in-state generation against transmission. The Plan also calls for a transparent, public, IRP process in which industry participants, including the state's transmission companies can participate. Finally, the Commission staff and other participants investigated transmission options along with external wholesale market prices as an integral part of the Plan. I expect that the Commission staff will continue to evaluate transmission options along with other options in the future. As demonstrated by the Plan, Commission staff worked with transmission companies to carefully develop transmission options for meeting Michigan's needs, and will play an integral role in any subsequent IRP filing. I am confident that these recommendations will allow for fair and balanced IRP results.

5. **It seems the up front approval process in general gives short shrift to an important issue going forward. With the separation of transmission and generation, how does Michigan law assure a fair process in which the most cost effective infrastructure solution is determined?**

The Plan's recommendation for an open and transparent IRP process along with the other provisions discussed in response to questions 2, 3, and 4 will go a long way to assuring that the best infrastructure solution will be made for Michigan. As noted on page 18 of the Plan, an IRP filing by a utility would require the utility to "assess the availability and cost of external market power and transmission options that could help satisfy its capacity needs." These recommendations will result in a fair and balanced simultaneous evaluation of both transmission and generation options.

During modeling for the Plan, transmission companies were invited to participate and played a major role in assessing transmission options. Staff invited the transmission companies to propose transmission upgrades to expand access to external capacity and energy, and incorporated all of the transmission companies' proposals into the modeling scenarios. I would expect future staff and Commissions to continue this coordination with the transmission companies.

6. **During committee, you testified that the construction of new transmission is "a FERC matter." However, doesn't the MPSC still have large role to play in transmission? Is not the MPSC required under Michigan law to approve the sitting of major new transmission lines? Approval of the sitting of a new line requires the MPSC to examine costs, need, routing and public benefits of a proposed line before giving approval. Given this MPSC power over the sitting of transmission lines, isn't it still going to be the case that the MPSC will have to make decisions with regards to whether new generation or new transmission is built?**

Michigan law does give the Commission jurisdiction over siting major, new transmission lines, so we anticipate being involved in transmission lines in the future. The law does require the Commission to examine the cost, routing, construction, and benefits of a proposed route. However, the planning for major new lines is performed at MISO which may approve a transmission owner's request for a new line as part of the Midwest Transmission Expansion Plan. Once this has been approved by MISO, the transmission company must then seek approval from the Commission if the proposed line is rated at 345 kV or above. If the Commission does not grant approval, the transmission company may then seek to have the proposed line declared a National Interest Electric Transmission (NIETC) corridor, which would allow the federal government to site the line. The Energy Policy Act of 2005 permits certain transmission corridors to be designated as a NIETC by the federal government.

Recently, MISO has indicated that it is exploring the option, along with the U.S. Department of Energy, to make siting of major transmission upgrades in this region (running from the Dakotas to Ohio) a federal jurisdictional decision through a NIETC corridor designation. If this occurs, it may allow MISO, FERC, and DOE to preempt Michigan's transmission siting law.

7. **The Plan's analysis seems to begin with the assumption that expanded transmission would only serve to reduce Michigan's planning reserve margin and would eliminate the need to construct combustion turbines. It modeled the reserve margin reduction as being a reduction from 15% to 12%. However, MISO also did a separate analysis and found that the planning reserve margin for Michigan would be reduced to 10% not 12%. Under MISO's analysis expanded transmission would be a more advantageous investment. The question is why did staff reduce Michigan reserve margin by a lesser amount? Staff's change in reserve margin assumptions obviously makes transmission less attractive. However the Plan is silent as the analysis that led staff to reduce Michigan's reserve margin by a lesser amount.**

The economics of transmission versus in-state generation involves not only reserves but also the cost of energy in the external markets as well. The cost of capacity and energy savings together must offset the incremental cost of the transmission upgrade in order to make a proposed transmission line economically viable. It must also be assumed that those external capacity and energy sources will be made available to Michigan instead of to regions closer to the source.

The 12% reserve margin in the expanded transmission case originated in the Capacity Need Forum and was the product of a collaborative process involving numerous energy planners and other participants. Like this Plan, the CNF planners were attempting to determine how much reserve ratios should decline if transmission capability into the state was expanded. The 12% figure was widely accepted by CNF participants.

For the 21st Century Energy Plan, the same proposal was made to expand transmission capability into Michigan, during the scenario/sensitivity, load forecast, resource screening and data development phases of the modeling. This was undertaken again as a collaborative process, and, to my or my staff's knowledge, no one objected to the 12% figure. After the modeling assumptions for the Plan were made, and the modeling commenced, ITC made a presentation on the trade-off between transmission capability and reserve ratios. However, to our knowledge, no one suggested that the 12% figure be changed because of that study, or any other reserve ratio study.

One of many MISO exploratory studies, the Transmission Expansion and Generation Expansion Options report, assumed a 10% planning reserve margin. Studies such as this require simplifying assumptions regarding transmission and generation availability, fuel costs, operating life, planning reserves, etc. to run the models. Different assumptions will yield different results. For example, changing assumptions with respect to loop flows over the Michigan transmission system will cause a change in reliability for planning purposes. Loop flows are unscheduled power flows over the Michigan transmission system that are caused by generators and customers outside of Michigan. These flows can reduce the amount of transmission capacity that is available to Michigan customers.

Since MISO assumed the 10% reserve margin, I cannot answer for the assumptions or analysis on which it is based.

It is important to keep in mind that a change in a reserve margin assumption, without the proper amount of facilities to back up that assumption (either generation or generation plus transmission) could result in a higher probability of a loss of load. Both the CNF, and the Plan adopt a target 0.1 day per year probability of a loss of load, which has been the long-standing industry standard. Alternate studies may make differing assumptions regarding the acceptable amount of loss of load probability.

8. **On p. 28, Appendix Volume I. staff states:**

"MISO evaluates whether adjacent states are forecast to have sufficient reserves to support Michigan during peak periods and does indicate that nearby states are forecast to have sufficient reserves within its footprint in the 2009 period. This study's assessment of transmission as a method to provide access to capacity outside Michigan and to satisfy reliability needs relies on MISO's MTEP process and its determination that sufficient reserves exist to provide needed support (Emphasis added)." Given staff's stated dependence on MISO for critical reserve margin information, is it not incumbent on staff to explain why they did not accept MISO's 10% reserve margin finding and instead displaced it with their 12% assumption?

MISO did not make a reserve margin recommendation for use in the Plan. Staff relied on MISO's assessment that sufficient generation capacity would be available in nearby states at the time of Michigan's peak to "fill" transmission lines, and not be used up by load closer to the generation source. This MISO analysis was used in the loss of load probability study to determine how much external generating capacity Michigan could rely on through the transmission system in an emergency.

9. **The Plan recommends a new up front approval process for the construction of new generation. However, it does not provide for MPSC consideration and approval of new plant technology. Does this mean that utilities would be subject to after the fact prudency review of their choice of plant technologies? Wouldn't this omission lead utilities to adopt the most conservative least cost plant technologies? Would it cause utilities to exclude technologies such as nuclear or clean coal for fear of being attacked after construction on the basis of having chosen the wrong technology?**

The Plan's recommendations require the utility to justify the need for a proposed plant and demonstrate that it is the best option for meeting the customer's needs in light of known and likely contingencies, like fuel cost projections, air emissions standards, etc. As discussed in more detail on page 46 of Appendix I: "The IRP would also identify and examine major contingencies and explain why the utility's preferred plan is the best plan for its customers." As different plant technologies are evaluated, they will each have differing investment costs, impacts on air quality, permitting and siting issues, operating risks, and operating costs. Some of the new technologies may have higher construction costs, but may have off-setting reductions in operating costs, superior air quality profiles, etc. Therefore, I would expect that technology would be reviewed in the IRP process and would not cause a utility to exclude a preferred production technology.

10. One of the purposes of the Plan's policy recommendations is to provide a legal/regulatory climate in which new generation can be built. Will this approval process actually work? As I understand it a utility will not have an obligation to serve or build to serve customers who are not utility customers on the day a certificate is issued. If a significant number of customers are not utility customers on the day a certificate for a new plant is issued and a plant is sized to only serve customers served by a utility on that day, who will build generation needed for the significant number of customers who aren't utility customers when the certificate is issued? They will be in Michigan and expect power, but isn't it true that the utility will have no obligation to serve and build for them and merchant plant interests don't seem interested in building to serve markets? If enough are AES customers a utility might not even be able to present a case for construction of new generation.

I believe that the Plan's recommendation will remedy the flaws in Michigan's current hybrid market structure that undermine the ability to build new base load generation.

Currently, no one in Michigan has an obligation to build any generation. Michigan public policy has been to promote competition through energy markets, so it would seem that the default source of electric energy in Michigan is the wholesale market for both full service utility customers and customers electing service from a competitive supplier. This reliance exposes Michigan customers to very substantial fuel and market price risks, which have proven to be expensive and volatile over the past few years.

Utilities, however, do have an obligation to serve all customers requesting service and this obligation remains intact with the Plan. The issue is who has the obligation to pay for a new plant. Today, only full service utility customers are required to pay for a new utility constructed generating unit. The ability of customers to freely move between the regulated and customer choice markets and avoid paying for a new generating plant that is built to serve them creates too much uncertainty to finance a new plant on reasonable terms.

While there will always be some uncertainty as to a utility's customer base in Michigan's hybrid market structure, the Plan offers considerably more certainty for financing purposes than today's regulatory and statutory provisions. Once a certificate is issued, ratepayers who are customers of the utility will be obligated to help fund the plant, even if they leave the utility later. For those ratepayers who are not customers of the utility when the certificate is issued, but become a customer later, they will also bear a responsibility to pay for the plant as a utility customer. However, customers of an AES who remain with an AES can avoid the cost associated with construction of a new utility power plant, though they should see a benefit in the form of lower locational marginal prices (LMPs). This proposal will provide sufficient revenue certainty to finance a new electric generating plant on reasonable terms. I also expect that the construction of a new base load unit in Michigan will involve the participation of more than one utility, so I expect that the Plan's recommendations can result in an appropriately and economically sized plant for ratepayers. These recommendations should preserve the Michigan hybrid market system, which the legislature enacted through 2000 PA 141.

11. The Plan recommends that both utilities and AESs provide planning reserves for their customers. Should this Michigan legislation allow the MPSC to intervene only when the applicable RTO has not enforced a rule on this matter? If not, does the MPSC feel it necessary to issue competing reliability requirements with applicable RTOs? The issue is illuminated by the fact that PJM already has a rule that requires all LSEs to provide planning reserves, while MISO does not.

I would expect MISO, or a reserve sharing group created for compliance with Reliability First (the region's electric reliability council) to adopt reliability standards, including planning reserves. However, RTOs, the nation's ERO, NERC, and NERC's regional entities such as Reliability First are jurisdictional to the FERC. The Energy Policy Act of 2005 indicates that generation adequacy shall be left to the jurisdiction of the states. Since FERC and its jurisdictional entities do not appear to have the authority to enforce planning reserves, it is important that Michigan provide the Commission with the authority to enforce planning reserve standards that have been adopted by such regional organizations, fairly across all load-serving entities within Michigan.

I do not expect the Commission to issue standards that conflict with those adopted by NERC, Reliability First, MISO, or PJM. Instead, the Commission would likely need to enforce standards adopted by one of these organizations. If it is clear that NERC, Reliability First, or MISO has the authority to enforce planning reserve standards, then this Commission would not need to exercise that authority.

12. On p. 21, the Plan states "Residential service is heavily subsidized by commercial customers, and may be subsidized by industrial customers." You state a desire to remedy this situation. What is the estimated rate impact of this policy on residential customers once the MPSC has completed its cost of service adjustments?

The rate impact on residential customers would depend upon which cost of service methodology is used, the test year adopted, and expected sales. However, for the major electric utilities, the one-time rate impact could be approximately 1 to 1.2 cents per kWh.

13. In regards to a change to a Renewable Portfolio Standard, wouldn't a grant to the MPSC of the authority to double a RPS be an excessive delegation of legislative power? Why shouldn't a future legislature handle this issue?

The Plan calls for the Commission to "conduct a study to determine the cost and performance of the RPS, along with the availability and cost of renewable resources. . ." prior to increasing the RPS. The plan only recommends an increase contingent on the outcome of that study. The legislature has the power to direct the Commission to increase the portfolio after a study, and to address concerns over excessive delegation of authority, and could also establish specific criteria required to be met in a formal Commission case prior to increasing the standard. The benefits of allowing the Commission authority to increase the RPS are potentially lower renewable energy costs associated with program continuity and the opportunity that this may create for firms to enter the Michigan market. This opportunity will likely create more interest among wind energy companies, including manufacturers, and will encourage a greater supply of wind energy along with other renewable projects. These benefits should justify the delegation to the Commission of authority to increase RPS targets.

However, legislation providing that future adjustments to an initial renewable portfolio standard made only pursuant to legislative action is acceptable, as well.

14. **It appears the MPSC has deliberately excluded AEP's Indiana Michigan Power (I&M) affiliate from using the ACP as means to satisfy a RPS beyond 2012. Given its small customer base in Michigan (125,000), why did the MPSC choose to exclude I&M? Its small size makes reliance on renewable projects to comply with a Michigan only RPS expensive due to a lack of scale. This will be a problem unless Indiana agrees to jointly support a renewable project. Why take away this cost effective solution for Michigan customers?**

I&M was not deliberately excluded from the ACP. ACP's were recommended for the smaller utilities because of concern for their limited resources, including personnel available to contract with renewable energy providers or keep track of renewable energy credits. To keep compliance as simple and efficient as possible for these small utilities, the Plan recommends an ACP option. Some determination of what constitutes a small utility must be made in implementing this proposal and the 100,000 customer number was selected without regard to which utilities may be included and which may not. I would suggest that I&M, with a total of 500,000 customers, does not constitute a small utility, just like Wisconsin Electric and Wisconsin Public Service are not considered small utilities in the U.P., even though they have only 10% and 4%, respectively, of their sales in Michigan

15. **The economic viability of wind power is greatly dependent upon the existence of the Federal Production tax credit. It is a federal tax credit that the Congress has been extending on a year-to-year basis. Given the federal budget problems it may one day cease to exist. Why isn't there a reopener included in case the PTC isn't extended?**

Rather than try to identify all potential reasons to reopen the RPS, the Plan allows for a utility to seek a waiver based upon hardship or cost of renewable resources. The Plan's recommendations represent a flexible and practical opportunity to adjust the RPS as needed to reflect varying market conditions.

16. **It appears under this plan that all utilities must comply with the RPS regardless of their need for new capacity. Why should the customers of a utility that does not need new generation to serve its customers be mandated to financially support new renewable capacity? Shouldn't it automatically be considered a hardship when customers are asked to pay for the costs of new renewable capacity before capacity is even needed? Why not phase in the need for new renewable capacity when new capacity is actually needed?**

If utilities were allowed to defer any RPS commitment until they face a need for new capacity, they might defer that need through the use of short-term or intermediate-term capacity purchases. That would effectively continue the status quo, which cedes control of the portfolio standard to the utility. The Plan allows a utility that may not need additional generation to request an adjustment to its RPS through a waiver based on hardship or rate impacts. During this process, the Commission can be assured that the utility is not merely trying to indefinitely defer compliance. It should also be noted that a major function of an RPS is to initiate markets that will help reduce the cost of renewable energy facility development in Michigan. That will work to encourage important benefits through the utilization of indigenous power sources and the creation of local jobs in manufacturing, construction, and operations and maintenance.

17. **The Plan obviously creates a preference for the use of in state renewable resources. Won't this regulatory restriction create a higher level of demand on Michigan resources and thus raise the cost of a RPS? Hasn't this been a problem in other states? Similarly won't a RPS mandate to purchase renewable based electricity raise the price of that product as the seller knows the utility has to buy? Wouldn't this be especially true if the RPS level is overly aggressive in its estimate of economically harvestable renewables in a state?**

At this time, it appears that Michigan has sufficient in-state resources to meet the RPS targets established for 2015. Once an RPS has been adopted, I anticipate that renewable energy projects will be brought on-line fairly quickly. This could contain the cost of renewable energy and associated RECs. Further, I do anticipate that some utilities will construct their own renewable energy facilities and that these projects will serve as a cap on renewable energy prices.

The RPS will also signal to wind energy companies that Michigan is a good place to do business and should induce companies to build facilities here. The combination of more companies and a clear need for more renewable energy will result in more competition to build larger facilities that can take advantage of scale economies. This should keep prices in the range predicted in the Plan.

The Plan's recommendation for an alternative compliance payment should also act as a cap on renewable energy prices. Since the price of the payment is determined by the Commission and the payment acts as an alternative to the purchase of renewable energy credits, it will serve to "cap" compliance costs.

Finally, the RPS recommendation in the Plan to phase in compliance more slowly than some of the proposals now in the legislature should help avoid the rush to buy, which could cause prices to rise.

I do not believe that the RPS levels recommended by the Plan are overly aggressive. However, if the amount of renewable energy available is lower, or its cost higher than anticipated by the Plan, a utility may seek to adjust its RPS standard through a waiver request based on hardship or rate impact.

Among those states that have adopted an RPS, 13 have subsequently increased their standards, but none have decreased their standards.

18. The Plan provides for the MPSC to provide penalties for non-compliance with a RPS. Wouldn't it be inappropriate for the legislature to delegate wide-ranging power to determine penalties? This seems extreme. Why can't the legislature determine penalties?

The legislature has delegated the authority to levy penalties to the Commission in 2000 PA 141 (section 10c.). A similar grant of authority would prove instrumental in assuring that RPS standards would be met by Michigan load serving entities.

19. The Plan includes a discussion of placing distribution wires underground. Where did this come from? It wasn't mentioned in the Governor's Directive. Is it really an issue that is deserving of being discussed in the 21 Century Plan? Was there a workgroup on this issue? Wouldn't this mandate be extremely expensive?

This issue emerged as workgroup discussion progressed throughout the summer of 2006. One of the goals of the plan was to anticipate technology developments and power needs within Michigan. Power quality, especially associated with distributed generating resources and high quality, end use needs arose as issues. The Plan recommended a smart grid collaborative to address distributed generating technologies and placing more of the state's distribution system underground to address power quality issues. Unfortunately, recognition of the need to study underground facilities came late in the process and the recommendation was not studied by a workgroup. Therefore, the Plan recommends that the Commission study this option first.

At this time, no solid estimate of the cost of the underground recommendation has been made. The plan merely calls for the Commission to investigate the cost of extending its current underground policy. Only if an extension is deemed feasible, would the Commission commence rulemaking to extend its policy.

20. What kinds of programs would this new program operate? I read the description on pgs. 34 through 38 and it seemed awfully vague. What would consumers get for their $100,000,000 a year?

The $100 million funding recommendation was based upon a set of 30 end-use markets for which distinct incentive programs would be made available to Michigan energy consumers. The funding distribution of programs among the 30 end-use markets would be determined by the program administrator in compliance with MPSC guidelines. Michigan consumers would be able to participate in energy efficiency programs that would fall into the following end-use categories:

Commercial and Industrial:

High performance new buildings; unitary HVAC replacement and system improvements; lighting – remodeling and replacement upgrades; boiler replacement and systems improvements; chiller replacement and system improvements; ventilation system improvements; refrigeration system improvements; motors – new, replacement and repair; compressed air system improvements; fan and blower system improvements; pump system improvements; manufacturing process upgrades; water and wastewater system improvements; and agricultural energy efficiency improvements.

Residential:

Consumer electronics; compact fluorescent lighting; multi-family common area lighting; variable speed furnaces; central AC; multi-family heating system replacement; room AC; water heater purchases; new home construction; remodeling; dehumidifier purchases; direct install market; clothes washer purchases; and multi-family fuel switching.

Generally, energy efficiency programs will use incentives, like coupons and rebates, to encourage consumers to purchase highly efficient lights, appliances, industrial motors, processing machinery, and in some cases replace existing energy consuming equipment. Energy audits will help consumers identify problem areas that contribute to unnecessarily high energy use. The fund may also be used to provide for educational campaigns, and to encourage retailers to provide energy efficient products. These types of programs have been in existence for years in some states, like neighboring Wisconsin. These programs have been demonstrated to be a very cost effective option to meeting electric energy needs.

21. Would this new program supplant the existing energy efficiency charges and programs created by the MPSC in Detroit Edison and Consumers Energy rate cases?

No. The vast majority of the current MPSC program funding is used for low income bill assistance with some funding for low-income weatherization. In contrast, the Plan's proposal would be designed to use energy efficiency as a resource to meet future electricity needs and would be available to all utility customers in the state, not just low-income customers.

22. **As for load management programs, don't utilities already operate programs of this nature? If so, why does the MPSC need this new authority? Why won't utilities create such programs, as they are needed? It is their duty to provide reliability. Wouldn't this level of authority move the MPSC into the role of micro managing utility operations? Shouldn't the MPSC continue to assure that reliability is met with the utility determining the best/least cost means to provide reliability? More importantly are you suggesting the MPSC be given authority to mandate customers join such load demand programs? These would be a troubling expansion of MPSC powers. If you are not suggesting that the MPSC could mandate customers join such a plan is the MPSC asking for power to mandate utilities operate voluntary load management programs? Don't they already do this?**

There are only a handful of existing load management programs in Michigan, the largest of which is Detroit Edison's interruptible air conditioner program (approximately 330 MW of load). These programs can be highly cost effective since they displace load during critical periods in the summer, especially when prices are at their highest. By managing peak load, the utility's power supply cost can be reduced significantly. These programs can serve both a reliability and economic purpose.

Although utilities are responsible for electric reliability, the public and community leaders look to the Commission to assure reliability is maintained. Just as important, the Commission, ratepayers, and state government leaders have an interest in reducing power costs, especially during high cost, on-peak power periods. It may take granting authority to the Commission to assure that these reductions can be realized.

Currently, the Commission does not have authority to require utilities to implement or expand these programs and utilities have not significantly pursued expanded participation. The Plan recommends that the Commission be authorized to require that utilities implement or expand load management programs when they are cost effective and improve reliability. Exercising this authority would not be automatic. Only if utilities failed to investigate and implement or expand programs when it makes sense to do so, would the Commission exercise this authority. Participation by customers would be strictly voluntary.

Not all utilities operate voluntary load management programs, and participation for those that do could be expanded relatively easily. While this may appear to be micromanaging a utility, experience indicates that load management programs can serve an important role in reducing power supply costs and improving electric reliability, but utilities do not seem interested in using this option on their own.

23. **The Governor's directive states, "A renewable portfolio standard shall be created that establishes targets for the share of this state's energy consumption derived from renewable energy sources." Given this express directive from the Governor did you feel free to dissent and not recommend a RPS?**

Yes. But I, too, believe that it is time Michigan join the 24 other states in the Union that enjoy the benefits that come with an RPS. Since the Governor requested an RPS, and I believe in the concept, I included this resource option with whatever caveats were appropriate. Fortunately, compliance with the Governor's request also made sense with the results of the Plan's contingency analysis. Our analyses in both the CNF and the Plan show that an RPS pays off in managing fuel cost volatility and potential greenhouse gas emissions as a risk adjusted cost minimization strategy.

24. **The Plan projects that ITC's Detroit Edison region will violate the 1 day in ten years loss of load projection reliability standard. (0.3 vs. 0.1) However, the Plan assumes a 1.2% load growth forecast for Michigan as a whole, including the Detroit Edison area. (p.10). If the Detroit Edison forecast is used (.6%) isn't the risk of LOLP violations in the Detroit Edison pushed noticeably further into the future?**

Not necessarily. The LOLP study did include a low growth sensitivity of .3%. The lower growth does defer the reliability concern in Southeast Michigan by a year or two if one assumes the same on-peak transmission capacity as assumed in the Plan and if one assumes there are no loop flows over Michigan's transmission system. Reliability standards are violated in 2009 even at this lower growth rate when loop flows occur over the Michigan transmission system. This result occurred in the low transmission sensitivity, which assumed 1,500 MW of loop flows through Michigan to Ontario.

25. **It's also my understanding that a Detroit Edison employee stated at a Plan meeting that, if he were to change his forecast he would LOWER the growth forecast?**

The Plan made use of the most recent long-term forecasts available. The state forecast represents a composite of forecasts provided by Michigan utilities, including Detroit Edison's forecast of 1.2% over the 20 year period. Modelers also used a much lower forecast sensitivity which included a .3% growth rate for the first 10 years and .7% over the entire planning period. This lower growth rate sensitivity still resulted in a base load unit being brought online by the model in 2015.

Whether the growth rate is 1.2%, .7%, or 2%, any request by a utility to build a plant and receive a certificate will require an IRP be filed with an updated forecast. The updated forecast is a very important piece of information that would be used in the IRP analysis and certificate of need determination. It will also allow interested parties to question the forecast or the need for the plant.

26. Why did the Plan utilize a 1.2% forecast for the ITC/Detroit Edison area when Detroit Edison forecasted .6%?

Please see response to question 25. To my knowledge, the .6% growth rate was made after the Plan was completed. In addition to using the most recent growth available when the modeling program was being undertaken, the Plan also made use of a low-growth sensitivity. The low growth sensitivity resulted in a .3% growth rate over the first 10 years and .7% over the entire 20 year planning period.

27. If .6% is used as the load growth estimate when does the Detroit Edison area violate the 1 in 10 year reliability standard?

This growth rate was not used to test reliability. Please see response to question 24. Although this growth rate was not used to test reliability, and depending on assumptions regarding loop flows, the MPSC staff's best estimate is 2009 or 2010 for southeast Michigan.

28. It appears that your Plan found substantially greater renewable resources than were estimated in the CNF. How did this happen?

A part of the goal for the Plan was to more carefully estimate the amount of renewable energy resources available in Michigan. Most of the additional renewable energy is assumed to come from wind resources. In addition, the 21st Century Energy Plan process was able to mobilize additional contributions from researchers outside of the MPSC to complete a more thorough analysis of the state's biomass and wind resources.

The CNF assumed that only class four wind regimes measured at 50 meters could economically support wind energy resources. The amount of on-shore, class four wind regimes in Michigan has been estimated at approximately 840 MW by the National Renewable Energy Laboratory (NREL), based on 50 meter hub heights and validated by NREL using the best available public and proprietary wind monitoring data. This estimate was made after excluding certain areas within Michigan because of siting issues. Most modern wind turbines, however, operate at 70 to 100 meter heights. Wind shear at these higher hub heights very significantly increases the size of class four regions within Michigan. For example, nearly 700 MW of wind energy projects in Michigan's Thumb region have been in the MISO queue over the past few years, which is much more than suggested by the 50 meter wind maps. The Plan assumed that much of the Class 3 wind regions of the state when measured at 50 meters would be equivalent to class four at 70 - 100 meter heights. In addition, much more information is available to confirm the Plan's estimates, from such sources as the MISO queue, experience in other Great Lakes states, and ongoing consultations with NREL and various companies that have been doing wind energy prospecting in Michigan now for several years. Together, all these information sources provided the basis for increasing the estimated renewable energy available within Michigan. NREL has recently begun the process of estimating the amount of wind energy available to Michigan at 70 – 100 meters. Although it has not yet confirmed the amount through the required data validation procedures, the NREL estimate provides a basis for assuming that the Plan's estimate of wind energy is reasonable and easily achievable from a technical prospective. Attachment 1 a presentation from NREL covering their initial estimates for the 70 - 100 meter heights.

29. **How accurate can the assessments of wind in your Plan be given the following statement: "Estimates for Michigan's wind energy resources were based on data that generally depict wind regimes in the state, but should be supplemented by local wind studies." (see p. 26 of the Plan and Appendix Volume II, p. 137 discussion and footnote 58). How many actual wind studies was the 21 Century effort privy to?**

The Commission and staff do not have private meteorological tower data. However, Plan modelers were aware of the potential by reviewing the amount of wind projects requesting interconnection studies in the MISO queue and with Detroit Edison. See also the answer to question 28.

30. **Your Plan does not say much about transmission. However, staff states on p. 137 of Volume II that:**

"The amount of future wind development in Michigan may be constrained by the limitations of the existing transmission/distribution infrastructure and the costs necessary for upgrading it to accept large quantities of wind generation."
Would transmission problems that might impact wind development also impact the ability to implement an RPS?

Yes, and the Commission is actively investigating the interconnection issues.

31. **I believe that the CNF report looked at Class 4 winds as being suitable for development. However, staff says that:**

"If one assumes that a quarter of the Class 3 wind regions can be economically harnessed at 70-100 meters, that would still produce nearly 4,000 MW of wind capacity, (Emphasis added)."

Were these estimates based on assumptions or sound modeling, actual measurements, and data, or were these simply assumptions?

These estimates were assumptions based upon tentative results from NREL estimates. Please see answer to question 28 above and the NREL presentation (Attachment 1).

32. Did staff put the Plan's final wind resource assessment out to the renewables workgroup for comment? If so what was the reaction? If not, why not?

No. The Plan's schedule was ambitious and there was simply insufficient time to fully circulate the latest wind estimates.

33. Staff appeared to use an estimated cost of $1,425 per kW for installed wind capacity. (p. 122 Volume II). However, data from the National Wind Collaborative suggests that a figure of $1,680 per kW is more accurate. The difference is substantial. Please describe the actions taken by the 21 Century Energy Plan to determine an accurate up to date price for wind power.

Since data for the Plan was compiled, the cost of wind turbines, along with traditional generating technologies have increased. The price estimates for all generating technologies included in the Plan began with the CNF cost estimates. The cost of traditional power plants and non-wind renewable energy sources was then increased by 13% to account for the recent run up of commodity and labor costs occurring since the CNF was prepared. The cost of the wind machines was increased by approximately 16% based upon a higher estimated escalation rate for wind turbines. This higher escalation rate was developed from conversations with wind power developers and utility representatives, including those from at least one utility actually building wind power facilities.

In judging the costs used in the Plan, please keep in mind that the costs of all generation sources have been increasing and it is the relative price of wind energy to other sources that is important in determining the economics of wind energy. For this Plan we increased the cost of wind energy slightly more relative to other production technologies.

Notwithstanding the historical trend for wind energy costs to follow a consistent and gradual decline, both in absolute terms and especially in comparison to traditional fossil fuel sources, modeling for the 21st Century Energy Plan reflected the current short-term run-up in the price of wind generators. That increase in wind development costs is driven by the same market forces affecting all electric generation technologies.

34. What would be the required dollar investment to satisfy a 10% RPS, if you assume it can be satisfied entirely by wind power in Michigan with Class 4 wind areas? Please do not provide an answer in terms of the rate impact on customers.

The study did not assess the costs of renewable energy options in the absence of traditional generation and transmission options. Instead, it calculated the cost of renewables on a busbar basis and integrated the costs of those resources into the total costs of operating existing generating plants and acquiring new resources. The comparative costs of relying on various combinations of resources like renewable energy options, energy efficiency, transmission, and traditional generation can be found on page 23 of Appendix I.

As seen on page 23 of Appendix I, inclusion of a renewable energy portfolio standard lowers the cost of meeting Michigan's electric energy needs by approximately $1.5 billion over a 20 year period, on a present value basis, when compared to reliance on Michigan's current policy, which is based on a hybrid market. The current policy anticipates adoption of combustion turbines for reliability and growing energy purchases from wholesale electric markets.

In a separate carbon tax scenario, renewable options were estimated to save $1 billion dollars over 20 years, on a present value basis, when compared to a full complement of traditional generating plants, including base load units.

The scenarios shown in Appendix I include the costs of relying on various resources to meet Michigan's forecast need for electricity. It should be noted that renewable energy options are also expected to benefit Michigan's economy. A recent NextEnergy study, entitled "A Study of the Economic Impacts from the Implementation of a Renewable Portfolio Standard and Energy Efficiency Program in Michigan" (April 2007), for example, estimated that adoption of an RPS would create approximately 2,000 to 6,000 jobs in Michigan and modestly increase the gross state product.

Another study, by the Renewable Energy Policy Project, *Component Manufacturing: Michigan's Future in the Renewable Energy Industry*, published in November 2006 indicates that Michigan has the potential to play an important role in supplying renewable energy equipment. This study shows that Michigan ranks fourth in the U.S., after California, Ohio, and Texas, for the potential to support manufacturing jobs for components required by an expanded renewable energy industry in the U.S. T he study takes a detailed look at the county level, and compares the specific kinds of manufacturing at existing firms with the component parts required for renewable energy (wind, biomass, solar, and geothermal), and concludes that Michigan is home to over 950 firms that could be manufacturing renewable energy system components. Therefore, adopting an RPS will likely provide additional economic benefits to the state.

35. How would requiring Load Serving Entities to buy power from in state resources impact the costs of that power?

Please see response to question 17. The increased demand would, on its own, tend to drive up price. On the other hand, the current situation of market uncertainty and long lead times for developers drives prices higher and has thus far not encouraged major developers from working in Michigan. The phased-in approach recommended in the plan along with the tate commitment to renewable energy through a mandatory RPS is likely to increase participation from private firms seeking to build renewable energy facilities and, thereby, increase the potential supply of renewable facilities. As a result of the estimate of available renewable energy in Michigan, the phased in nature of the RPS, and offsetting effects of an RPS, we don't anticipate that the Plan's recommendations would cause costs to either rise or fall.

36. The working group held by the Senate Energy Policy and Public Utilities Committee on this issue suggested we needed a 30 year plan. How long of a period of time does your Plan cover. What length of time should it cover?

The Plan covers 20 years, and I believe that 20 years is the most appropriate timeframe covered by a long-term plan. The most important portion of the plan is the first 10 years, when decisions need to be made and work must begin to meet reliability and energy needs. This covers the near to intermediate period for which there is a relatively high degree of confidence in demand, technology, fuel, and plant cost estimates. Over the second 10 year period, confidence in estimates begins to decline significantly, but this period is needed to incorporate a long-term assessment that can be modified later and the end-effects of modeling different resources with different expected costs and lifetimes. Beyond 20 years, it is nearly impossible to project what type of technology or costs might be incurred in meeting energy needs.

37. Your Plan maintains that under the hybrid model of 14i, no new power plants were built. Could it just be there wasn't a need?

No. Two years of extensive modeling (the CNF and the Plan) has consistently selected a new baseload plant as soon as a plant can be built. Given the long lead times needed, I would have anticipated that a new base load plant would have been begun by this point. Moreover, this is a common pattern in states that have deregulated and adopted customer choice programs. For example, PJM has recently implemented a capacity market to encourage development of additional generation. On the other hand, in states like Wisconsin and Iowa, which have retained traditional regulation and not instituted customer choice, new base load facilities are being constructed.

38. Under your Plan, a plant could be constructed under the old model of used and useful or a new model that would be a certificate of need program. Wouldn't a used and useful funding formula be better for ratepayers than a certificate of need plan where it would appear that financing costs during construction could be placed on ratepayers?

In Michigan's hybrid market, the certificate of need plays an important role in mitigating risks associated with customer migration between the regulated and choice markets. For example, a new generating plant may seem reasonable at one point in time, but if customers migrate to choice as the plant is being constructed, the plant may look unnecessary when completed. This possibility puts the utility at a substantial risk and is likely to mean that new base load will not be constructed in Michigan. By mitigating this risk, the Plan permits more reasonable financing terms for a new plant and, thereby, it lowers the costs incurred in construction.

The inclusion of financing costs during construction can occur under the current used and useful policy or the Plan's proposed certificate policy. In fact, financing costs for new pollution control investment is currently permitted by the Commission's current ratemaking policy. The Plan would permit the extension of this policy to a portion, none, or all of the remainder of a new plant. The inclusion of financing costs during construction represents a tradeoff between slightly higher revenue requirements now or even higher revenue requirements in the future. Permitting recovery of none, some or all of the financing costs during construction would increase the current revenue requirement (rates) somewhat, but it smoothes any rate increase associated with a new plant. The current ratemaking policy requires that most of the construction financing costs be capitalized and recovered after the plant becomes operational. This increases the rate impact of a new plant once it becomes operational. The tradeoff is pay a little more now or even more later, when the plant becomes operational.

Even though the Plan offers more certainty and addresses some of the flaws in Michigan's hybrid market structure, it does not relieve the utility of prudence review of the plant's actual cost, once completed.

39. Some suggest that a cap should be provided on construction costs to prevent cost-over-runs. We seem to have a history of cost-over-runs in Michigan. Is some type of cap desirable?

A cap could be useful and I wouldn't necessarily oppose one. However, I think that a thorough prudence review after the plant is constructed could prove more useful.

40. Current return to service provisions requires a customer to give roughly six months notice before switching. You propose a two-year window. It has been suggested that this will kill competition in Michigan. Will it?

Not for those customers who strongly believe in and have confidence in markets and would prefer to take service from a choice supplier. The Plan's proposal would make migration back and forth between the regulated utility and the choice market more difficult for those customers seeking to benefit from temporarily lower market prices and require them to weigh potential gains against the risks of relying on an energy market for power. This is necessary, however, to protect customers who have no choice of suppliers.

The current policy is that once a customer leaves, they must take service from a choice supplier for a year. The customer may return after one year, however, in order to receive service at cost of service rates and avoid paying market prices during the summer months, the customer must notify the utility by December 30 for the coming summer months.

The greatest impediment to retail competition has been the course of market prices, which have approximately doubled over the past three or four years. When the volatility of market prices is also considered, the movement to customer choice is expensive and risky. I believe that this, together with the removal of credits that were granted to incent choice activity, have had and will have a greater impact on customer choice participation.

The recommendation for a two year return to service provision is designed exclusively to protect customers who have decided to not become customers of an AES or to whom AESs do not provide service. As explained on page 22 of the Plan, and more thoroughly on page 44 of Appendix I, Michigan's experience has shown that customers who remain with the incumbent regulated utilities have paid hundreds of millions of dollars to maintain the Michigan electric generation system for those customers who want to take advantage of temporarily lower market prices and then, later, return to the utility's service when market prices increase. When these choice customers return, the incumbent utility must secure sufficient power in a high market price environment. In order to protect long-term customers of the incumbent utility, particularly residential customers, the two year return to service provision will allow the utility the time needed to secure sufficient power to serve the returning customers.

41. Did the Governor's requirement for a MANDATORY RPS hamstring your ability to offer the best possible set of options and recommendations?

No. Renewable energy options play an important role in managing future risks and uncertainties, such as any future greenhouse gas control requirements or fuel cost volatility. Renewable options play an important role in balancing future risks and costs, which is why the CNF also recommended adoption of renewable energy.

42. Your Plan requires a RPS for muni's, but no planning or operating reserve margin? Shouldn't all customers be assured of reliability? Shouldn't everyone be treated the same?

I would agree that all load serving entities should be required to contribute to maintaining electric reliability in the state. Our experience, however, has been that some AES suppliers have not maintained appropriate planning reserves. However, it would be advantageous to have a planning reserve standard that is applicable to ALL load serving entities within the state, including municipalities.

43. You discuss solar power as a potential option in Michigan. Is it really an option?

Solar electricity has the potential benefit of providing zero emissions energy during the peak summer months when power is most expensive and which is the seasonal NOx emissions limit period. I think that this option, although presently much more expensive than other options, should be studied through a pilot program because it can contribute to managing on-peak loads and costs. There may be some circumstances where the locational value of distributed energy resources, including solar, makes them cost effective today, even though those distributed resources may be much more expensive compared to traditional power supply options. However, it is practically impossible to capture and analyze those locational values when conducting a statewide study, like the 21st Century Electric Energy Plan.

44. It is clear that most residential customers aren't benefiting from choice. If rates are further deskewed, residential rates will rise. Do you think that AES's will then do

more to attract residential customers? Should we require that an AES market and retain a certain percentage of residential customers?

Residential customers do not appear to be migrating to the choice market in those states that have fully deregulated. It is not clear whether this is due to AESs not marketing to this sector or the desire by most residential customers to remain with their incumbent utilities. This is discussed more thoroughly in a report prepared by Ken Rose for the Virginia State Corporation Commission dated August 27, 2006. Mr. Rose has testified before the Michigan legislature on a couple of occasions about retail electric competition programs.

The state of Pennsylvania has arbitrarily assigned residential customers to choice suppliers in an effort to encourage its competitive market. This seems counterintuitive; depriving customers of their choice of suppliers in order to preserve the choice program. Likewise, forcing choice suppliers to market to customers they don't want in order to preserve their ability to choose customers seems counterintuitive.

45. You discuss the need to look at modifying building codes to produce more energy efficient homes and buildings. What do you think that would do to the housing market?

Improving the energy efficiency of new homes at a modest cost may make the initial cost of a new home-greater than without new standards. On the other hand, a more efficient home that reduces energy costs would serve as a selling point for new homes. Over time, any additional costs of constructing a home with greater energy efficiency would be more than offset by reduced energy costs. On balance, it would seem that the marketing and long-term cost advantages of more energy efficient homes should offset any detrimental effect that may be caused by raising the construction costs. Adoption of an updated code could lower construction costs relative to maintaining the existing code as discussed on pages 116-118 in Appendix II of the Plan.

46. Can state government do more to conserve energy? If we are going to require energy efficiency programming, shouldn't we lead by example?

The Governor's Executive Directive 2005-4 does just that. Provisions of this directive include reduced energy use in state buildings, consideration of energy efficiency in state purchasing, and energy efficiency design standards in state building construction. A copy of the directive is attached for your review (Attachment 2).

47. The Status of Electric Competition Report provides benchmarking data for electricity prices, but the Plan provides no benchmarking .Why are no benchmarks offered in your Plan?

The Plan includes a comparison of future generation costs to Michigan ratepayers based upon alternative resources, risks, and future scenarios. It is not practical to make this long-term comparison with other states, given the vast amounts of data and forecasts needed for each state.

48. When the Commission unbundled rates, separating power supply charges from delivery charges, it appears to have led to an increase in choice distribution rates. Did this action by the Commission contribute to the decreased participation in choice programs?

The principal contributor to decreased participation has been the increase in market prices, which have approximately doubled over the past three or four years. Please see response to question 40. However, the movement to cost of service distribution rates occurred at the same time as prices in the energy markets were increasing and may have contributed to customers returning to incumbent utilities. It is important, though, that distribution rates be the same for similarly situated choice and bundled customers.

49. This Committee heard a presentation earlier this year by two University of Michigan professors on global warming. One of them believed your call for a coal-burning generating plant was incongruous with the Governor's call for the state to be a leader in alternative energy technologies. How do you respond to this?

The Plan, following on the CNF, represents two years of assessing risks and resource costs. The conclusion of the studies is the recommendation for a balanced portfolio of resources including energy efficiency, renewable energy options, and central station options. It is important to remember that multiple retirements of older baseload generation is forecast to occur over the planning horizon, and it is doubtful given these retirements that reliance on energy efficiency and renewable energy facilities alone can provide the balance of cost, risk management, and reliability needed in the future. Keep in mind that the risk of future coal construction will be evaluated closely in the IRP process, and all new generation would need to meet the "Best Available Control Technology" for air quality as set forth by the Michigan DEQ.

50. How does DTE's recent announcement — coming/list one week after the Plan was issued — to build a nuclear power plant impact the Plan's statement: "nuclear power was eliminated from consideration due to its long lead time and concerns over the permanent disposal of spent nuclear fuel"?

Nuclear power is an option for meeting future baseload need, but because of the long lead time need to have a plan certified and a plant sited, it is not likely to be operational in the first half (the first 10 years) of the planning horizon.

An additional issue that may slow adoption of nuclear production is the additional time it may take to resolve issues related to nuclear waste disposal.

It is conceivable that a nuclear plant could be built in the state, but due to certification, siting and disposal issues, not until the second half of the planning horizon.

Should DTE file an IRP or request a certificate of need for a nuclear facility, it would need to be evaluated against all possible alternatives and the contested case would allow for DTE to present their case, as well as allow for challengers to be heard.

51. How does the DTE announcement impact the Plan's conclusion that current financing options effectively prevent the construction of base-load generators?

It does not impact the Plan's conclusion. DTE has only made an announcement. It is doubtful that serious engineering and construction will commence until the uncertainty associated with Michigan's hybrid market are resolved.

52. Explain the apparent incongruity of your statement on p. 16 of your Plan that: "major utilities are unwilling to sign a long term PPA with an IPP" and the current potential sale of a major utility (Consumers) generator to an IPP and its entering into a PPA with that IPP.

Palisades is not a new plant and represents an exception, as part of a national trend involving nuclear units.

The chief reason for selling Palisades is the cost of being a single unit nuclear utility. Maintaining nuclear units requires unique engineering skills and a staff to monitor and respond to Nuclear Regulatory Commission safety and operational standards. Although the fuel costs for a nuclear plant like Palisades are minimal, the operating costs can be significant because of the expense incurred to maintain these unique skills and staff for a single unit. The national trend has been a consolidation of nuclear unit ownership, so that larger firms now own multiple units and can realize economies of scale and lower operating costs. Moreover, nuclear issues can take a disproportionate share of senior management's time. Issues like reactor head replacement require considerable time and attention. Again, for firms with multiple units, the cost of this time and attention can be spread over more than one unit.

Palisades has been operating with a favorable capacity factor and producing energy at a very modest variable cost. It has provided fuel price stability during a time period in which market prices have been driven by volatile natural gas prices. The power purchase agreement (PPA) captures this fuel price and power cost stability at the same time that it allows Consumers Energy to lower its overall operating costs by selling the unit to a firm specializing in nuclear plant ownership and operations.

Finally, the statement referred to in this question refers to new generating plants and to long-term PPAs. It is likely that PPAs will be signed for a shorter-term duration, since it is not possible to construct a new generating plant overnight. However, it does not seem likely that in Michigan's hybrid structure that a regulated utility will sign a long-term PPA and commit to a large fixed price payment for the cost of a new plant, not knowing what its load will be in the future.

53. Why does p. 17 of your Plan states legislation is needed to "enable the construction of new generation," yet, footnote 22 on that same page states "The Commission. '5 current rate treatment for new generation will also remain available."

The Plan's IRP process requires the utility to investigate and assess the need for additional generation in the light of resource options that it may not ordinarily consider as part of its business strategy, like energy efficiency and renewable energy options. It also requires the utility to assess regional and wholesale market purchase opportunities along with expanded transmission. These options are open to public scrutiny through a contested case process, which is the "quid pro quo" for a certificate of public need. Utilities may prefer to forgo this scrutiny and accept the burden of demonstrating the need and prudency of a new generating plant after construction on their own. The Plan allows for this option.

I believe that legislation will be needed to enable construction of new generation; but nonetheless, current rate treatment for new generation remains available.

54. Why does the Plan state on p. 19 that: " of a power purchase agreement has sonic important advantages' but only list disadvantages? What advantages of competitive bidding do you believe exist? Why were they not listed?

While there are some apparent advantages, they are limited or illusory. Advantages are discussed on pages 48 and 49 of Appendix I. The disadvantages, however, outweigh the advantages. Competitive bidding may work for simple and easily constructed combustion turbines. These units are easy to site and have standard features. Competitive bidding for these units may permit an accurate price comparison and assure that the lowest cost is realized when combustion turbines are built. Another advantage proffered by some Plan participants is the assertion that competitive bidding will protect against cost overruns and shifts operating risks to the (independent power producers) IPP. However, this protection is either illusory or comes with a price. As noted on page 47 of Appendix I:

> "These risks, along with other unforeseen risks, require that much care must be exercised in a competitive bidding process. It is not clear that all these risks and uncertainties can be identified in an RFP process. Some independent power producers (IPP) participants propose that the preferred way to handle these risks is to treat the IPP like a regulated utility. They reason that if the regulatory process allows a pass through of costs incurred by a utility, it should also allow a pass through of those same costs incurred by an IPP.
>
> "Regulated utilities, however, are subject to prudence review, and any attempt to pass through costs can be closely scrutinized and costs can be disallowed, if that is appropriate. IPPs, on the other hand, do not come under the Commission's jurisdiction. The Commission cannot scrutinize costs incurred by these entities, nor can it penalize IPPs for engaging in imprudent practices by reducing their rates of return."

The Plan makes competitive bidding an option for utilities, but not a requirement. A more thorough discussion of the advantages and disadvantages is included on pages 19-21 of the Plan and pages 46-50 of Appendix I.

55. **What do you believe the state can do to eliminate the barriers in our law, rules, or policy that impede the introduction of new technologies in energy production and distribution as soon as possible and address the interconnection uncertainties referenced on p. 26 of your Plan?**

Adopt the Plan's recommendations. The Commission has already begun this process by launching a review of its interconnection policies. Implementation of the Plan's recommendations for demand response programs and a smart grid collaborative will likewise advance the goal of introducing new technologies.

56. **Has the PSC released any reports in recent years indicating that Michigan may need as many as 18 additional base-load power plants by 2025? How many plants?**

Model results for both the CNF and the Plan forecast the need for multiple units over the next 20 years. The exact number depends on which growth rate and resource scenario that this selected. However, there are scenarios in which the model selects 18 or more base load units over the 20 years in both the CNF and the Plan. Keep in mind that many of these are selected to replace retiring units.

Although the model selects numerous baseload units, I do not expect to need nor do I recommend adopting a Plan that includes more than one or two baseload units. Instead I recommend a balanced approach to meeting Michigan's future resource needs which includes evaluation of energy efficiency, load management, and renewable energy options, transmission upgrades, along with traditional generating plants.

Therefore, the Plan, like the CNF, recommends the addition of only one or two units over the first ten years of the planning period, and periodic reviews to update and adjust the Plan as circumstances change.

57. **Your presentation before the Senate Committee you indicated Michigan is in imminent need of one or more new base-load power plants within the next 10 years. To clarify matters, please indicate whether you believe the state will need**

I believe that the state needs a balanced approach to meeting its future electric energy needs, which includes all the resource that you cite below. I have recommended that one or two new base load plants be built between now and 2015, but that the need for the second plant be reviewed periodically. The bullets below appear to be results from the model, but I would be reluctant to adopt these recommendations without qualifications. I believe that periodic reviews need to occur after one plant is begun to continually assess the need for additional base load plants.

- **3 new base load power plants if neither a 10% RPS nor AET is implemented?**

  The model selects four, if the base forecast is used; assuming AET refers to the energy efficiency program.

- **2 new base load power plants if only a 10% RPS or AET is implemented?**

  The model selects two to three plants if the base forecast is used.

- **1 new base load power plant if both a 10% RPS and AET are implemented?**

  The model selects one new plant if the base forecast is used.

58. Governor Granholm's Executive Directive 2005-3 calls for all purchasing contracts for the state to be competitively bid. Do you believe that there is, or should be, an exception for the state's purchase of electricity?

While competitive bidding should be considered, this is something that would be addressed by DMB. Each electric customer should decide what purchasing strategy best suits their needs.

59. How much electricity does the state purchase per annum? At what cost?

I do not have the number of MWhs purchased per annum at this time. The annual cost of electricity for 2006 was approximately $50 million.

60. Were each of the increased wind assessments (identified on pgs. 123-138) subject to review and comment? If not, why not? If so, what were the response(s)?

No, unfortunately there was insufficient time to fully circulate the increased wind estimate prior to the report's release. Much of the increased capacity comes from estimating the effects of wind shear when moving from 50 meter heights to 70 – 100 meter heights, especially in light of the large number of wind projects in MISO's queue for the Thumb area. This has taken time to assess and use for future estimates.

It should be noted that MPSC staff has been consulting with NREL regarding Michigan wind resource assessments, and NREL believes the 21st Century Electric Energy Plan assessment is overly conservative. NREL has projected Michigan's on-shore technical potential from wind generation, for example, to be approximately 16,000 MW. Although not all of this could be sited, the state's potential could easily satisfy the proposed RPS.

61. How do you rationalize using progressively larger wind sources (from 420 MW to 4,000 MW) in the following scenarios:

The "rounding up" of the CNF report assessment (420MW) to 443 MW (which seems to equate to meeting a 7% goal) (footnote 1, p. 123)? This was done for modeling purposes, but was not an actual recommendation of the CNF.

- **The increase of the CNF assessment to 525 MW (p. 123)?**

  This amount is not a CNF figure, but a new estimate for the 21st Century Energy Plan based upon wind projects in the queue at MISO. Not all queue projects were included in the 525 MW, only those deemed likely to actually be constructed. Based upon current queue projects and interconnection studies, we still believe that this number is achievable based on current queue data alone. The MISO queue currently includes 15 Michigan projects under development in 10 counties, for a total of about 1,450 MW.

- **The increase in the wind assessment to 2415 MWs (p. 138)?**

  Please see response to number 28.

Given the fact that the CNF found only Class 4 winds are suitable for development, why did you assume that ¼ of Class 3 wind regions can be economically harnessed at 70-100 meters to produce 4,000 MW of wind capacity?

Please see response to number 28

62. **Does your Plan account for the potential that wind developers might make multiple transmission requests to MISO?**

    Yes.

63. **How does your Plan prevent wind developers from simply adding the cost of transmission to its bids? How does your Plan measure the threat of higher market prices for renewable sources caused by a mandatory RPS?**

    It is possible that interconnection costs may be added to the cost of a wind developer's bid. Likewise, interconnection costs incurred by regulated utilities or anyone else building new generation in Michigan would be added to the cost of power coming off those new generating units. Interconnection cost recovery by wind developers is no different than recovery by any other power plant owner.

    The Plan minimizes any price impact of an RPS by gradually phasing in the requirements. It is important to avoid creating too great of a rush to build or secure renewable power, which would tend to cause prices to rise. The Plan takes a much more measured approach when compared to some of the legislation introduced in the House and Senate. This will allow the industry time to acquire the needed resources on a reasonable schedule and avoid the rush to construct all at once. The timing is also projected to take advantage of technological improvements that are likely and expected to occur in the future.

    It should also be noted that a mandatory RPS can serve to reduce renewable power costs, by providing long-term, stable markets for the power produced. Renewable resource power costs in Michigan have been higher than in many other states, in part because of the long lead times to obtain all necessary approvals and the lack of long-term contracts for the sale of electricity generated.

64. What are the increased costs associated with increasing wind mill sizes from 70m in height to 100 m in your model? How did you measure these costs and how did you factor those increased costs in to your assessment?

Our estimate of wind energy production costs was based on the cost of 70 meter machines. New wind turbines presently coming into the marketplace are based on 80m and 100m tower heights, and using longer blades. It is expected that the added construction costs for the taller towers and longer blades will be offset by greater electricity production available because winds are somewhat faster and steadier at the taller tower heights. Since the model made use of busbar costs for wind, these offsetting effects should not have an impact on the relative costs of wind relative to the cost of conventional, fossil, generation.

65. How do you reconcile the 20% standard with the Governor's call for a 25% RPS by 2025 in her recent re-election campaign?

The 20% standard refers to electric energy only. The 25% standard refers to all energy sources in Michigan.

66. Your Plan states on p. 28 that renewable energy credits (REC) can be purchased from out of state resources "as long as the REC produced an air quality or economic benefit in Michigan." How will you measure that?

It will be the responsibility of the utility that relies on out-of-state RECs to demonstrate these benefits.

67. Please identify unnecessary barriers to renewable alternative and distributed energy applications.

A major barrier has been the transmission and distribution interconnection process. The distribution interconnection process is undergoing review at the Commission now.

68. Why does the Plan limit net metering to facilities less than 150 kW in size?

The 150 kW size limit is a product of the collaborative process. Some participants preferred a larger size, some preferred the current 30 kW size. The 150 kW recommendation was designed as a compromise between these positions. Also, MPSC Interconnection Standards Rules are presently formulated for the following size categories of electric generators: < 30 kW, < 150 kW, <750 kW, <2,000 kW, and equal to or greater than 2,000 kW. Less than 150 kW was selected in part because that is a next logical step in the progression, given the size categories already adopted by the Commission in its rulemaking process.

69. **Why do you propose the creation of the Michigan Energy Efficiency Program (MEEP) – which you termed "another government bureaucracy" during your testifying before this Committee – by PSC action and not legislative enactment?**

The use of government bureaucracy was unfortunate since I believe it results from a misunderstanding. I believe that the program requires legislative enactment, and I am seeking legislative support for the program.

The program goals, objectives, funding, evaluation, monitoring etc. will go through the Commission. I anticipate we will need perhaps three to four full time employees to implement this program. However, the program itself will be carried out by private sector firms and this will minimize the number of PSC employees needed to implement the program.

70. **How would customer surcharges be affected if the MPSC is unable to obtain financing for the MEEP from outside sources?**

The surcharges are normally computed based upon full program costs. Any outside financing sources would either reduce the surcharge or allow an increase in program size.

71. **Why does the Plan provide an opt-out from MEEP for large industrial consumers when small businesses could also demonstrate they have energy efficient programs?**

First, our experience has demonstrated that the large industrial customers have processes that are unique, for which energy efficiency programming must be designed carefully. I want to avoid a situation in which an energy efficiency program disrupts a complex industrial process.

Second, because of the unique nature of industrial process, cost efficiency gains normally incurred by increasing a programs size are not likely to be realized.

Third, these larger industrial firms have energy engineers on staff who can recommend energy efficiency measures that would not impede and may improve the industrial process.

These characteristics are not as common in small businesses.

72. **According to the Plan, at least 13 other states require some form of competitive bidding including many non-restructured or deregulated states. Shouldn't Michigan require competitive bidding as a means to assure customers that they are paying for the least cost option especially when you consider the magnitude of the investment and the utilities' track record of building new baseload generating facilities (i.e., FERMI II, Palisades, Midland, etc.)?**

While I believe that competitive bidding should be an option for utilities, I do not believe that it should be mandatory. Pages 46-50 of Appendix I discuss the merits and drawbacks of competitive bidding in detail. Although bidding seems to offer some important benefits – for example, proponents of competitive bidding tout cost advantages of IPP construction – these cost advantages can only be achieved through a high degree of debt leverage that the utility's balance sheet must support. This lowers the utility's credit worthiness and increases its cost of capital. This increased cost of capital is passed on to ratepayers through the earnings permitted on the utility's other investments. Thus the utility's overall revenue requirement increases to offset the "seemingly" lower cost of a highly leveraged IPP plant.

Once a utility's plant has been paid-off by ratepayers, it continues to produce power and ratepayers benefit by only paying for the fuel and operating costs. However, after ratepayers payoff an IPP plant through a PPA, they must either pay for the plant again through another PPA, or purchase the power from the plant at market prices. Again, although the initial cost appears lower, because of the leverage (debt financing) involved, over the long-term an IPP plant could cost twice as much as a rate based plant.

As mentioned previously, the disadvantages of mandatory bidding are many, and I would urge you to read pages 46-50 of Appendix I along with pages 19-21 of the Plan for a more thorough discussion of competitive bidding.

73. According to the Plan, the utilities' Integrated Resource Plan will include an assessment of alternative means to meet future demand for electricity, the cost of each option, the utility's plans to manage future fuel, environmental, and other risks, and a financial plan for constructing the plant. The IRP must also incorporate energy efficiency and renewable energy targets. Is transmission included as a component of the utilities' IRP?

Yes. As noted on page 18 of the Plan: "It (IRP) would also be required to assess the availability and cost of external market power and transmission options that could help satisfy its capacity needs." Also, please see responses to questions 2, 3, 4 and 5.

74. Why does the Plan relegate any discussion of transmission enhancements in the Lower Peninsula of Michigan to a single footnote?

Extensive analysis of transmission capability and expansion options was performed in both the CNF and the Plan. Appendix G of the CNF report, consisting of 21 written pages and 14 charts, includes a detailed discussion of existing import capability, potential improvements, and contingencies due to loop flows. This analysis, with updates, was incorporated into the Plan. Transmission is discussed on pages 72-77 in Appendix II and on pages 18, 19, 22, 27, 28 and 29 of Appendix I. Numerous modeling scenarios involving transmission expansion and contingencies were modeled for the CNF and the Plan. In this process, the International Transmission Company (ITC) was given a freehand to propose transmission upgrades, and these upgrades were incorporated into the Plan's modeling phase.

75. Isn't transmission potentially a lower cost option for consumers?

A major portion of both the CNF and the Plan was devoted to assessing this question. As noted above, extensive modeling scenarios and sensitivities were used to answer this question. The answer is provided on page 29 of Appendix I:

> "Electric transmission expansion can be expensive: a 2,500 MW DC line across southern Michigan was estimated at $800 million, using existing right-of-way. The transmission expansion cost allocated to Michigan ratepayers for the proposed transmission upgrade does not include the cost of the capacity and energy at the other end of the line. The cost of capacity and/or energy at the other end of the line plus the cost of the line allocated to Michigan ratepayers must be less than the cost of building and operating plants in Michigan for the line to be economical. The Federal Energy Regulatory Commission (FERC) provided liberal rate treatment for transmission investment, allowing ITC the nation's highest rate of return on investment that Staff is aware of for FERC jurisdictional utilities. ITC's charges amplify the transmission costs and, because customers must also pay for the power at the end of the line, the charges contribute to putting the transmission option at a cost disadvantage to in-state generation. The Plan's analysis indicates the transmission expansion option is more expensive than building generation in Michigan, even though the planning reserve margin is lowered to 12 percent and six combustion turbines are dropped from the generation mix in the expanded transmission sensitivity. Further, it is possible that some, or even most of the transmission upgrades will be reserved by out-of-state market participants and not be available for Michigan market participants. For example, although the CNF study estimated that 3,000 MW of on-peak transmission will be available into Michigan, approximately 800 MW has already been reserved by other market participants and, therefore, unavailable for Michigan reliability planning. Nevertheless, the value of expanding transmission capability to reduce reliability costs and further integrate Michigan into the Midwest market should continue to be studied as a long term goal of the plan."

It should be noted that in assessing the value of transmission upgrades, market price forecasts were made for all control areas in the eastern interconnection over the entire planning horizon. A very substantial effort has been made to fairly and accurately compare the transmission option with in-state generation options.

Since modeling for the Plan was commenced, ITC announced an alternative transmission option involving a 765 kV transmission line with a price tag of $2.5 billion.

76. **Should the enhancements to the transmission grid be considered before the utilities go down the path of investing billions of dollars in new power plants?**

Yes, and these options have been considered simultaneously in both the CNF and the Plan. We anticipate that they will also be compared simultaneously in any IRP filed with the Commission as part of a certificate of need case. Please see responses to questions 2, 3, 4, and 5.

77. **Recently, ITC Transmission and AEP announced plans to commence a study of building a 765kV transmission network in Michigan's Lower Peninsula, potentially in both 1TC Transmission and METC's service territory that would link to AEP's existing 765kV transmission infrastructure. Why didn't the Plan even consider this option?**

This proposal is briefly discussed on page 77 of Appendix II, but was made after modeling for the Plan had been completed. Therefore, we could not comment on the likely economic impact of this proposal.

78. **What about energy efficiency and conservation? Does the 21st Century Energy Plan's load growth projections incorporate energy efficiency and conservation? That is, is the 1.2 percent annual load growth reflective of energy efficiency and conservation efforts?**

The growth rate reflects normal efficiency gains that occur over time as appliances are replaced or new standards are promulgated.

79. **Aren't the utilities more inclined to build new generation rather than in vest in energy efficiency and conservation since their earnings are tied to new investment and energy consumption?**

It would be reasonable to assume that this is the case. The Plan calls for a statewide program run by an independent energy efficiency program administrator for that reason.

80. **Essentially, once the certificate has been granted to the utility, there would be no ability for the Commission or the State of Michigan to question the prudence of the power plant or the costs of such a facility, correct?**

No. The need for the plant could not be challenged. However, the cost of construction would still be subject to prudence review.

81. **What would the effect of this policy have been on the Consumers Energy Midland facility?**

There would have been no difference in the outcome. The need for Midland was not the cause of disallowances related to the plant, instead costs incurred during the construction of the plant resulted in disallowances. The Plan's proposal would also allow for this disallowance.

82. The Plan states that customers returning to full service will receive regulated rates two years from the date of notification that they wish to return. The utility will use its best efforts to provide electric service at market rates during that two-year time period. Customers leaving full service after a Certificate of Need has been granted will carry a surcharge with them for the new plant. If all load serving entities are required to maintain planning reserves as the Plan states, why should customers of those load serving entities be required to fund a utility power plant?

If a customer takes generation service from a utility and the utility builds a power plant to serve that customer, the Plan concludes that the customer caused the costs to be incurred and will be responsible for a portion of those costs if the customer later leaves the utility for an AES. This may have little or nothing to do with planning reserves.

If a customer takes service from an AES and continues to take service from an AES, then the customer will not have to pay for a new utility power plant. Again, this has little or nothing to do with planning reserves.

83. Based on your argument, all customers benefit from the construction of a new power plant, correct? By that logic, should all Michigan electric consumers pay for the new power plant? That is, if DTE builds a new power plant should the customers of Consumers Energy and the municipal and co-ops also pay for the new power plant?

In all likelihood, many of the benefits would be geographically limited. Because of the geographical nature of these benefits and for practical reasons, it seems appropriate to tie the benefits to specific service territories.

84. Aren't the customers of an alternative electricity supplier addressing their capacity needs via the alternative supplier and the alternative suppliers planning reserve requirements? Why should they pay twice? Assuming for argument's sake that customers of an alternative electricity supplier are required to pay a surcharge for the new utility power plant, why should there he any restrictions on their return to service? Aren't they paying for the new power plant? Shouldn't they be allowed to return to the utility to receive service from the power plant they are paying for? Shouldn't they get something since they are paying for the new power plant?

Experience has indicated that generally, AES suppliers do not maintain planning reserves. This has been evidenced through the annual filing of supply plans that the Commission requests of Michigan load serving entities. Instead, planning reserves, and the associated costs for the entire state are picked up by incumbent utilities and funded by utility customers. Please see question 11. There is currently not any entity that has jurisdiction or authority to enforce planning reserve requirements on Michigan load-serving entities. The Energy Policy Act of 2005 indicates that resource adequacy policy shall be left to the states, and Michigan requires legislation in order to enforce the regional planning reserve standards as set forth by NERC's regional entities.

Please keep in mind that the Plan's goal is to preserve the customer choice program while protecting the customers who have no choice of suppliers from the movement of those customers who do have choice between the markets.

Finally, the Plan recommends that if the AES customer did not contribute to the need for the new plant, the customer would not be assessed a surcharge.

85. The Plan states: "The ability of customers to move between the regulated and competitive markets creates permanent uncertainty about the size of the customer base for both utilities and AESs. This uncertainty makes planning and financing of expensive, long-lived baseload generating units very difficult. Because of their obligation to serve all potential customers in their territory, the utilities bear the responsibility to plan (and construct) for this load, despite the fact that customers may migrate at any time from the utilities' regulated rates to the competitive sector's market rates."

Hasn't DTE announced plans to invest over $1 billion in new technology to reduce emissions at their existing generating facilities? If the Plan's statement is correct, wouldn't the utilities have the same problems financing upgrades to their existing plants? Are they experiencing any problems?

Normally this might be the case. However, the new technology is intended for existing coal fired generators that are largely depreciated and have comparatively low fuel costs. The investment is spread over multiple units, so that the costs are manageable for each of the units. These are plants that are quite economic, and the additional investment will not change that status.

86. What facts did you rely on to reach your conclusion that the uncertainty makes planning and financing of expensive, long-lived baseload generating units very difficult?

The experience of deregulated, choice markets around the country, studies and reports, and discussions with participants in both the CNF and Plan.

87. Did staff talk to any actual banks that lend money to utilities for these types of investments? Did you simply rely on one statement from Fitch and the assertions of the state's utilities?

See response to question 86.

88. Is there any chance that the state's utilities are simply using this issue to restrict or eliminate competition?

I don't want to speculate on utility motives however, PJM's experience is worth noting. In a bid to encourage construction of new generation in its largely deregulated markets, PJM has devised a capacity market proposal. Thus customers must pay for both energy in an energy market, and then pay, separately, for capacity in the capacity markets. Customers must participate in these markets, or may self-supply energy and capacity resources. Although described as a market, capacity prices are determined, in part, by PJM administrative decisions. This is an effort by PJM to assure a sufficient stream of revenue is available to fund new generating plants. Capacity markets initiated in both the New York and New England capacity markets serve the same purpose.

I believe that some type of assurance must be provided in order to enable construction of new generating plant on reasonable terms.

89. The Plan recommends that all load serving entities will be required to maintain planning reserves; and the Commission will be authorized to penalize entities that do not meet the reserve requirement. Isn't the Midwest Independent System Operator (MIS 0) is currently addressing resource adequacy on a regional basis? Aren't all suppliers in Michigan required to meet the operating reserve requirements of the North American Electric Reliability Council (NERC)?

At this time, it appears that there is a gap in enforcement of planning reserve requirements. Reliability First, NERC's regional entity for our region, has established a planning reserve standard, however, it does not appear to have the authority to enforce standards regarding resource adequacy. Further, MISO does not have authority to enforce planning reserve standards. Therefore, it would be prudent to provide the Commission with this authority, so that the Commission could enforce Reliability First standards. If Reliability First or another entity is eventually empowered to enforce the standards, then the Commission would not need to enforce the standards.

90. Hasn't the Midwest ISO stated in sworn testimony before the Federal Energy Regulatory Commission that operating reserve obligations are more effective at ensuring reliability than planning reserve obligations?

My staff is unaware of the testimony to which you refer and inquiries to MISO have not produced any such testimony. However, to ensure electric reliability, both types of reserves are necessary. Operating reserves ensure reliability in the short-term or operating day. Planning reserves ensure long-term reliability and allow for sufficient operating reserves to be present in the operating day.

Operating reserves serve to ensure reliability during the operating day and are necessary should contingencies occur. Operating or contingency reserves are resources that are either spinning (running at a low level and may be ramped up within 10 minutes) or are quick start (resources that may be started and ramped up within 10 minutes). Planning reserves consist of all of the installed capacity resources in the region and a level of planning reserves is necessary due to unforeseen circumstances such as forced outages, derates, load forecast uncertainty, planned and unplanned maintenance events, etc. Based upon all of those stated assumptions that go into long-term planning, planning reserves could be thought of as a safety factor, so that after all the uncertainties play out, there will actually be enough operating reserves present to serve load.

91. The Plan states that a utility may seek a waiver from the RPS for one year based on hardship, or if compliance causes rates to rise above an amount deemed reasonable by the Commission. Why does this waiver only apply to a utility and not all load serving entities subject to the requirement?

It should apply to all load serving entities.

92. Please indicate whether the Plan itself is a product of the best judgment of the MPSC Commissioners and Staff based on the input from all interested parties. Were there other views? Where are these recorded?

The Plan is my best judgment based upon all the input that we received from interested parties. Many comments and viewpoints have been summarized in Appendix II, and all have been included on the Plan's website for public viewing.

93. Please explain the process leading to issuance of the Governor's Executive Directive 2006-02.

The process leading to the Governor's directive actually began on August 14, 2003, when North America experienced a blackout that served to remind all of us that the reliability of our nation's electric grid cannot be ignored. The Commission's report on the blackout recommended among other things, that Congress mandate electric reliability standards. On a state level, the Commission further focused on reliability issues, when in late 2004, it required a Capacity Need Forum investigation into the need for additional generating resources in Michigan, the need to prepare for future contingencies, and the need for modifying Michigan's electric energy policy under the constructs of existing Commission authority. The Governor's directive builds upon the findings of the Capacity Need Forum, and adds the opportunity to fortify Michigan's economy as a goal of energy planning by requesting policy recommendations that allow for Michigan to implement changes necessary to meet the challenges of its energy future.

94. ED 2006-02 makes certain conclusive findings, namely: (I) Michigan can become an "alternative energy development epicenter" and (2) a renewable portfolio standard should be created that establishes targets. Are you aware of studies or collaborative proceedings that supported these determinations of the executive order?

Yes, The recently completed study entitled "A Study of the Economic Impacts from the Implementation of a Renewable Energy Portfolio Standard and an Energy Efficiency Program in Michigan" by NextEnergy for the Michigan Department of Environmental Quality.

95. Under traditional regulation, was the determination of the type of generating technology left to management of the utility to determine based on its needs?

Yes.

96. The proposal calls for an integrated resource plan (IRP) filing. Under the IRP option, does the MPSC take over determination of the appropriate generating technology, such as coal, nuclear, gas or renewable?

No. I believe that the need to prepare a comprehensive IRP in order to request a certificate of need will require utility managers to weigh all resource options, along with future risks and uncertainties and this will greatly assist with resource decision making. Final decisions on whether to build a plant or not build a plant, or the type of plant to build is always vested with utility managers not the Commission.

97. Will the IRP proceeding be open to intervention by other interested parties favoring a particular technology, such as renewable energy?

The IRP process will be conducted as a formal case and parties will be permitted to intervene if they can meet the requirements for intervener status.

98. Won't the certificate of need determination by the MPSC require a balancing of interests among the participants, and even political compromise?

A certificate of need determination will be based upon evidence of need, following an open, public process to determine the likely growth of electricity use in the state, all available resources for meeting the prospective need, and balancing future risks with resource costs. I fully expect any utility applying for a certificate of need to offer participation in the project to other Michigan utilities, to consider resource decisions being made by other Michigan utilities, and to discuss the proposal with other industry participants.

99. Is this better than leaving the decision to management?

I strongly believe that this process will provide valuable guidance to management. Before the era of highly volatile natural gas prices, greenhouse gas concerns, and customer choice, there was little need for utility management to solicit support or advice from other parties, and a utility can still conduct its business in this manner. However, given the uncertainty created by environmental controls , customer migration associated with the customer choice program, and fuel cost volatility, it may be reasonable for utility management to seek advice and input on resource decisions from other parties. I think that this strategy improves a utility's decision process.

100. **What about the Supreme Court's Union Carbide decision holding that the operation of the utility business should be left to management?**

If legislation recommended by the Plan is enacted, Union Carbide should not be an obstacle to implementing the Plan.

101. **After a Certificate of Need is issued and after the plant is constructed, can the MPSC still review the prudency of the costs of the technology selected, versus other options that might have cost less?**

Yes, the prudency of the plant's cost could still be reviewed. However, I anticipate that the production technology would be subject to review, analysis, and comment during the IRP phase. The IRP should include a thorough discussion of a broad set of resource options and a thorough discussion of available production technologies. In this process, I would expect that the utility would justify its proposed plant, including the production technology that it has selected. If it can justify its technology selection through this process, I would not recommend allowing parties to challenge it later; however the cost of construction could be challenged.

102. **After a certificate is issued, the only conclusive item is need but cost overruns would still be subject to disallowance?**

Yes, cost overruns would still be subject to disallowance.

103. **Should there be a series of interim prudency reviews to update the certificate for cost and other project changes during construction?**

The Plan does not call for interim prudency reviews. However, interim reviews could prove useful to assuring that a utility is on track with its construction schedule, and this would give the Commission an opportunity to signal concern to the utility of schedule slips.

104. **Is it important to maintain Michigan's hybrid market with elements of retail competition and unregulated competitive generation service? Why?**

It may be useful to maintain the hybrid market for some additional time, if the changes proposed in the Plan are adopted. The customer choice program has cost those customers remaining with the utility hundreds of millions of dollars to fund the billing and metering systems needed to implement choice and to maintain the generation system in order to allow choice customers to return to the utility when market prices rise. The costs imposed on residential customers who have no choice, and business customers who prefer not to take service from an AES represent a considerable burden. Adoption of the Plan's proposal would help remedy this financial burden. At the same time, maintaining the choice program would allow Michigan customers to benefit by selecting to participate in the choice program if market prices were to decline significantly.

105. What does it mean to say that the hybrid market can be "sustainable?"

If Michigan's hybrid market is not modified, Michigan's ratepayers will become progressively more dependent on wholesale market prices. These markets have become more dependent on natural gas fueled units to set prices, and these prices have risen dramatically over the past three or four years. As a greater percentage of Michigan's electric energy consumption is purchased in the wholesale markets and Michigan electricity prices rise, there may be a movement to eliminate the choice market, as we have witnessed in Virginia, Delaware, Montana, California and others

106. Do you believe that uncertainties with the hybrid market are contributing to the inability to finance construction of new generating plants in Michigan? If so, why?

Yes, this was discussed in the report on pages 15 and 16 and in Appendix I at pages 42-45. The fact that customers can migrate rapidly from regulated service to the choice program (or back to regulated service when market prices rise) means that revenues can change by hundreds of millions of dollars over a year or two. This potential revenue swing makes it difficult to predict future customer base and cash available for fixed charge coverage, a financial measure used to determine the likelihood that interest and debt payments can be made on schedule.

The uncertainties of the hybrid market cause the business and financial risk of incumbent utilities to increase and make it difficult to finance a new generating plant, especially baseload, on reasonable terms.

107. Under the hybrid market, is it still true that almost no residential customers are offered electric generation service by competitive suppliers?

Yes.

108. If electric rates are increasing and few customers have competitive choice of suppliers, is it time to abandon Act 141?

This is certainly a good time to have an informed debate on the issue. But, this is a major public policy decision that must be made by the legislature and the Governor.

109. Act 141 represented government intervention to restructure the electric industry in Michigan. This Plan calls for more government intervention to determine generating resources, mandate renewable energy, increase net metering and create a new centralized efficiency program. Is it time to consider less rather than more government intervention in the electricity market?

The electricity market seems to be the exception to the rule that less government regulation will lower prices. In those markets that have deregulated, prices have risen considerably and, in some of those states that have deregulated, there are attempts to re-regulate the retail electricity markets (Virginia, Montana, Delaware). Even in Illinois, industry participants are suggesting that price caps remain in place, rather than allow distribution utilities to charge market prices.

Electricity has long been recognized as affecting the public good, and state government has a vital interest in assuring that sufficient, affordable power is available to businesses and residential customers. Markets, acting without government intervention in this industry, have not provided both reliable and affordable electricity.

As the state's and the nation's demand for electricity grows, the task of meeting this demand has become more difficult with increased reliance on market forces and the potential for major greenhouse gas controls. The electric generating industry will likely be one of the primary industries most affected by greenhouse gas controls. Repeatedly, modeling has shown that this is perhaps the most serious contingency likely to be faced by the industry. Since approximately 60% of Michigan's electric generation is sourced from coal based generators, the state's exposure is very significant. Unless the state requires adoption of a balanced and forward looking portfolio of resources, Michigan will expose its ratepayers to future cost increases that can be avoided by adopting renewable energy and energy efficiency options.

These programs have the added benefit of managing fuel related risks. As witnessed over the past few years, both natural gas and coal prices can be affected by events beyond our control. Managing fuel related risks includes making use of resources that we have not traditionally relied on and that will require a more robust regulatory regime.

110. The Plan says a mandatory RPS is a "win-win" proposition. Did you conduct an independent study to determine that the benefits out weigh any costs? If so, what are the costs?

The benefit/cost tradeoff for renewable energy is very dependent on the likelihood of greenhouse gas emissions controls, fuel cost increases, and Michigan regulatory policy. The benefits of renewable resources are based upon the low/no emissions profiles for these resources along with the fact that they are generally not dependent on fuel costs and associated escalation. To test the benefits of renewable resources, the Plan modeled a number of scenarios, including a scenario in which a carbon tax was placed on electric generation. When compared to a plan that uses only traditional baseload, combustion turbines, and nuclear plant options in a carbon tax scenario, the use of renewable options lowered the cost of supplying Michigan's electric needs by approximately $1.1 billion on a 20 year present value basis. This occurred even though the 2006 cost of renewable options was greater than power from traditional base load power plants.

Likewise, compared to the base (no change in Michigan policy case and only combustion turbines are added for reliability), renewable energy options decreased revenue requirements by $1.4 billion on a 20 year present value basis. This demonstrates the value of renewable energy resources in avoiding expected natural gas fuel costs.

However, when compared to a plan that includes traditional base load generation, but is not subject to carbon controls, renewable resources were projected to increase the costs of supplying electricity by $780 million on a 20 year present value basis

A comparison of the ten and 20 year present value costs for all the scenarios and sensitivities examined in the Plan is shown on page 23 of Appendix I. Pages 12-35 provide a description of the data, modeling format, resources examined, and results of the Plan's modeling phase, along with the recommendations resulting from the modeling effort. Based on the modeling scenarios and sensitivities performed for the Plan, renewable resources add net value to a portfolio of generating resources by helping to manage risks while containing costs.

111. The Plan seems to say we should follow the lead of other states with a mandatory RPS. Does that mean we shouldn't make an independent evaluation based on circumstances here in Michigan?

The Plan does not suggest that Michigan should follow the policies of other states merely because they have already adopted an RPS. Instead, the Plan compiled a comprehensive set of data, identified major contingencies that may face the industry in the future, and then sought to minimize the cost of electric generation services, while managing those contingencies. One of the major contingencies, if not the most significant, is future carbon taxes or greenhouse gas controls. The plan demonstrates that future costs that may arise from this contingency can be substantially reduced by relying on a balanced portfolio of resources including renewable energy and energy efficiency options.

Of course, also underpinning the recommendation for an RPS is the lack of emissions of renewable generators that improves the environment for all, and the economic benefits related to development of significant renewable generating plants.

I would add that we have kept nuclear based generation in the mix for the same reason. Although due to a number of factors, I don't think that nuclear generation is likely in the first half of the planning horizon, it may be a viable resource option for the second half of the Plan. In fact, modeling seems to favor nuclear baseload over coal in the carbon tax scenario. This modeling, however, is based upon very preliminary and uncertain nuclear plant costs. Until permitting and siting schedules and construction costs are known with a higher degree of certainty, it may be prudent to consider the nuclear option in the second phase of the planning horizon.

Finally, The RPS scenario lowered electric costs in Michigan relative to the current policy scenario that assumes the status quo of Michigan's hybrid market. The current policy scenario assumes that only combustion turbines are built to preserve reliability with a growing percentage of energy needs being purchased in wholesale markets.

112. The Plan says the state should encourage wind turbines, biodigesters, solar and fuel cells. Should our residents be ordered to pay more than market rates to support these technologies?

While these technologies may cost more in the near-term, they will pay off in the long term by mitigating the impacts of both fuel cost increases and future air quality constraints. When looked at over the long-term, and as an "insurance" against future risks, these resource options should pay for themselves.

See also the answers to questions 34, 94 and 111.

113. The Plan states that new wind development has been slowed by various uncertainties. Would it be fair to say that the main factors are (1) wind power costs more than other sources; and (2) wind power is intermittent and thus less useful to the grid system because it may not be available when needed most?

While the intermittent nature and cost of wind energy have been cited as impediments, the Plan's reference to slowed development refers to siting and interconnection issues faced, not just by wind energy, but by other renewable energy options as well. The Commission is currently reviewing distribution interconnection standards with the goal to make the process more efficient and less costly. This should address one of the impediments to wind generation.

Although wind energy may generally be more expensive than traditional generation today, in suitable locations wind-energy can compete with fossil based generation alternatives. That is why wind energy has been growing at such robust rates worldwide. The nature of wind generator output and its variability and geographical diversity is not well understood in Michigan, to date, and Michigan utilities have no experience operating a system with significant wind energy input. The primary value of the wind resource is for the fuel and air emissions that it can displace, and a secondary value is for the capacity afforded.

Recent studies show that significant percentages of wind energy can be incorporated into a state's (or a country's) power mix, with low additional operating costs. The studies typically show that the added operating costs can be offset to a great degree by the addition of the wind resource with its associated long-term fixed price, and the benefits of greater fuel diversity.

114. The RPS mandate would apply to all load serving entities in Michigan. What if a utility already has adequate capacity during the period through 2015?

If the utility already has sufficient capacity and the requirement to purchase renewable energy imposes a hardship, rate or otherwise, the utility has the option to request a waiver.

115. If renewable energy is available at a reasonable cost, wouldn't a utility want to purchase it instead of more expensive options? Doesn't the MPSC require in the PSCR (Act 304) process that utilities make reasonable and prudent purchased power decisions?

As indicated previously, renewable energy options are likely to be somewhat more expensive than traditional resource options, in the near term. In Michigan's hybrid market, any near-term cost increase due to renewable energy would contribute to putting the utility at a cost disadvantage to AES competitors, and act as a disincentive to purchasing renewable energy.

The PSCR process does allow the Commission to review resource decisions made by utilities. As a practical matter, this can be quite difficult with the authority vested in the Commission today. The Union Carbide decision circumscribes the Commission's authority when it appears that the Commission is making management decisions. Therefore, legislation authorizing the Commission to establish a mandatory RPS is necessary to assure renewable resources are adopted by utilities.

116. Are renewable energy developers privately owned companies? By forcing a market for privately owned renewable energy producers, would government be in effect taxing private citizens to benefit private interests?

This would not represent a tax. Ratepayers would be charged the cost of acquiring electric energy that is used to serve them. The cost of power to ratepayers is a blend of power from units with varying costs, including nuclear, coal, hydro, natural gas, etc. Renewable energy from wind or other sources is just another category of a diversified power portfolio.

117. Are you aware that many of the smaller cooperatives and investor-owned utilities in Michigan have reported no need for additional capacity in the state due to alternate plans? For example, companies in the Upper Peninsula are relying as generating resources under construction in Wisconsin, and Indiana Michigan Power Co. has a 2,000 MW nuclear unit in the state with far more capacity than it needs for the small Michigan service area. Why should these companies, and their Michigan customers should, be forced to pay for new capacity of any type that isn't needed?

The purposes of an RPS have been clearly laid out in many of the above answers. All citizens of Michigan, our utilities, and the economy benefit from an RPS. All should participate in the Plan.

118. The Plan proposes an alternate compliance payment for utilities serving fewer than 100,000 customers, to fund renewable projects through a state fund. If these companies have no need for new renewable capacity, won't you be taking their customers' money and devoting it to projects serving somewhere else?

Please see response to question 114. In addition, the proposal for funding renewable energy projects through the state fund incorporates a provision to try to match project funding to the service territory from where ACP revenues originate.

119. Early in the Plan, there are some specific criticisms of nuclear and fossil generating resources, such as problems with emissions, fuel costs and waste. Yet the discussion of renewable energy touts various benefits with practically no mention of issues such as above-market costs, limited resources (wind speed), sitting difficulties, lesser availability and operational difficulties. Before imposing an RPS mandate, shouldn't there be a full debate and cost/benefit discussion of renewable options?

While there are a number of issues related to renewable energy facilities that may impede or limit their effectiveness, most of the issues have been included or dealt with in the Plan's modeling phase. For example, page 54 of Appendix I identifies general barriers to renewable energy penetration into Michigan's generation mix. Other issues related to renewable energy are discussed below.

Near term busbar costs of renewable options are likely to be higher than for traditional generation. Another example is the Plan's estimated costs of renewable energy options relative to traditional generating options, based on expected specific technology costs. Appendix II, pages 67 and 127, show cost assumptions by production technology. For traditional technologies, fuel and emission allowance costs and escalators are shown on pages 21-30 along with forecast external market electricity prices. Most renewable options are not subject to fuel or emission allowance costs.

In addition to specific technology costs, the Plan includes the impact on total costs over the entire 20 year planning horizon of various resource options. The answer to question 110 discusses production technology choice on total costs.

Renewable resource options are estimated to cost more than traditional generating options in 2006, and this difference has become greater between traditional generation and wind generation in the Plan, when compared to the CNF. Traditional and non-wind renewable energy generating construction costs were increased by 13% for the 21st Century Electric Energy Plan over the CNF plan. Wind resources were increased 16% by comparison. Moreover, without the federal Production Tax Credit, wind energy would be approximately 25% more expensive than currently estimated for modeling purposes.

In estimating the cost of wind energy, we have flowed the benefit of the production tax credit to ratepayers. Should the production tax credit not be renewed, the cost of wind energy would rise very significantly.

These cost differences (not including expiration of the production tax credit) have been included in the Plan's modeling phase.

There are other difficulties in planning around renewable installations, especially wind power. In some areas of the state, it should be relatively easy to have wind powered installations sited, but in others, siting could prove an obstacle to successful installation of wind facilities.

As noted previously interconnection at the transmission and distribution level has also made construction and integration of some renewable energy facilities difficult. The Commission is currently reviewing its rules and regulations related to the interconnection process at the distribution level to assure that these will be fair and efficient and not be an obstacle to development of renewable energy facilities.

Wind, which is anticipated to play a major role in the RPS, is a variable power source. This has been a concern among planners for some time. However, work done by Minnesota and other studies around the country indicate that operational issues related to the intermittent nature of wind are manageable, at reasonably low cost, for the size of an RPS contemplated for 2015. (See also answer to number 113.) The Plan calls for a Commission study prior to 2015, to determine whether the RPS should be expanded thereafter. At that time, the Commission can determine whether wind will still be expected to play the dominant role in providing renewable energy and, if so, whether operational obstacles will emerge as the amount and percentage of wind energy continues to increase.

Although many issues related to renewable energy have been included by the Plan, the assumptions made by the plan could turn out to be incorrect, or other circumstances may arise that would prompt a review of the role of renewable energy in meeting Michigan's future energy needs. The Plan includes an opportunity to review these future possibilities and adjust the RPS through the waiver process.

120. Didn't a representative of Xcel Energy, which has experience with a large amount of wind energy, recommend that Michigan adopt voluntary RPS targets at first? Why isn't this mentioned at all in the Plan?

Michigan currently has a voluntary system, and it has produced negligible amounts of new renewable energy in recent years.

It should also be pointed out that in Minnesota, in which Xcel is a major utility, a mandatory RPS was adopted to replace the voluntary RPS. Also, Wisconsin, in which XCEL operates, has adopted a mandatory RPS, and Colorado, in which Xcel operates, adopted an RPS by referendum.

121. **The RPS would impose specific, measurable costs based on the projected cost per kW of the technology, the useful output and associated costs such as site and system costs or the need for backup power. Where in the Plan is a specific determination of the costs of the proposed 10% RPS?**

No specific determination of the cost of a 10% RPS has been included in the Plan.

122. **Wind power in other states as well as Michigan has been controversial due to opposition to the appearance of the towers, the large amount of land, noise and killing of birds or bats. Wouldn't it be more reasonable to develop a few projects and see how the problems are handled before mandating a major expansion of the capacity?**

Numerous wind energy installations have been brought on line across the country including Minnesota and Wisconsin. Given the experience of neighboring states, it does not seem necessary to experiment with wind energy installations here in Michigan. Problems with birds and bats have been addressed by wind generator manufacturers and by siting protocols, which now require extensive wildlife studies before new wind turbines are sited. The Audubon Society has recently endorsed wind energy after comparing the dangers and benefits of wind energy to other electric generating technologies. Problems with noise are also being addressed by manufacturers and can be minimized through proper siting.

Because the RPS is ramped up over a period of years, it is expected that the wind installations would be ramped up in the same manner.

123. **Would you agree generally that the utility grid in Michigan was designed to take power from large central station generating plants and distribute it to customers in the utility service territory? The Plan proposes that the Commission establish tariffs for use of a utility's distribution system to transmit electricity from customer-owned generators to the wholesale market. Were any studies conducted to determine whether this is workable from an operational standpoint?**

I would agree that the utility grid in Michigan was designed to take power from large central station generating plants to customers in each utility's service territory. Although no specific studies were performed to determine whether transmitting power to the wholesale market is workable, it does appear that based on our experience this can be done effectively.

The Public Utilities Regulatory Policies Act requires utilities to buy power from small power generators. The utilities must buy this power, if offered the power by a small generator, must pay its avoided cost for the power, and must transmit the power to its customers. At least one utility is already offering small generators an equivalent version of the Plan's proposal, by buying the power at the wholesale locational marginal price (LMP), but that utility is distributing it to its own customers.

I am aware of another Michigan utility that has already offered to transmit power from a renewable energy facility on its distribution system to a wholesale pricing node on the transmission system.

Although no studies have been performed, this is occurring in one fashion or another, and adoption of distribution use tariffs will eliminate some of the uncertainty regarding rates, terms, and conditions of this service and enable more small, renewable energy facilities to be sited and built by Michigan citizens. The Plan's recommendation for a smart grid collaborative is intended , in part, to maintain reliability and improve efficiency when smaller generating units are added to the grid.

124. The Plan states that the energy efficiency programs in place in the 1980's were halted because of utility restructuring and anticipated reduced costs from competitive markets. Isn't it also true that these programs were vigorously opposed by the large industrial customers, due to their administrative and program costs?

These programs were opposed by ABATE, and ABATE would need to disclose its reasons. However, actual independent program evaluations indicated that the programs proved to be cost effective. This was especially true of the industrial energy efficiency programs, with average costs of conserved energy in the range of 1 to 2 cents per kWh.

125. The Plan states that Michigan needs a comprehensive energy efficiency program and proposes a single, statewide program. Isn't a reasonable alternative to a statewide program to have programs developed and implemented on a utility-specific basis?

This would be a reasonable alternative and is used in some states. However, it lacks the many advantages of a single statewide program. A single program for the state would result in economies of scale that would be of particular value to smaller utilities that do not have the staffing capability of larger utilities. A statewide program would also avoid confusion arising from some ratepayers having programming available and others, perhaps living across the street, would not be eligible for the program. Finally, a statewide program would make it much easier to take advantage of trade allies, like retail stores for stocking energy efficient devices, lowering costs to ratepayers.

126. In MPSC Case No. U-14667, didn't the MPSC Staff conduct a comprehensive review of energy efficiency programs and recommend measures to encourage utilities to pursue energy efficiency programs?

Yes, it did review energy efficiency programs and recommended measures to encourage utilities to pursue energy efficiency. However, the goal of these recommendations was to work within the current scope of the Commission's authority.

127. The Plan claims that the energy efficiency program could save $3 billion in electricity costs over 20 years. What specific efficiency measures to be implemented through this program would account for most of the savings?

The programs providing the highest contributions to energy savings are commercial lighting, industrial process improvements, pump systems, and residential compact fluorescent lighting programs.

128. The proposed program calls for initial annual funding of $68 million to be adjusted upward to $110 million by the third year. Was any specific analysis conducted to determine whether immediate benefits would be obtained under the program to offset these costs in the early years?

Benefits are created in the first years of the program, but most benefits accrue over time as the programs are implemented and scaled up. This is not unlike construction of a power plant in which costs are incurred up front, but benefits flow over many years.

Expected energy savings in the first year of the program are 657 GWh, growing to 8,474 GWh in year 10. If the program is ramped up to $110 million over a three-year period, I estimate that the annual value of energy savings (at 6 cents per kWh) will exceed annual program costs (of $110 million) in the fourth year of operation. The simple payback period is approximately 5 years. The levelized per unit cost of saved energy over a 10 year period is under 3 cents per kWh.

129. The Plan devotes a considerable amount of discussion to the program structure and the need for an administrator, oversight education and marketing. How much of the initial funding will be devoted to these administrative and start up costs? At what point will the benefits of the program surpass the administrative and other costs?

It is estimated that a statewide program would entail an approximate $3 million one-time start-up cost, spread over the first three-years of the program operation. This expense would translate into an average program start-up cost of $100,000 for 30 programs. Start-up costs for individual programs would range from $50,000 to $200,000. During the course of operation of the statewide program, ongoing administrative costs borne by the program administrator are estimated to be about 5% of total program expenses.

130. Energy efficiency is a complex subject with many variables. Benefits are occurring all the time, as new appliances are purchased, compact florescent light bulbs find increasing use and customers modify their behavior. At the same time, new uses for electricity are found all the time, such as flat screen televisions which utilize more energy than the sets they replace. Is it possible for a program administrator to evaluate the costs and benefits with so many variables? In developing the program recommendation, how much consideration did you give to the difficulty of providing accountability? Can we really expect an efficiency program to have a significant impact on demand, if it results in a lower price for electricity reducing the incentive to conserve and other alternative uses continue to multiply?

It is possible for the program administrator to evaluate costs and benefits of these programs, and this is done routinely in those states that maintain energy efficiency programs. Remember, once an appliance purchase decision is made, the energy use of the appliance is set for its useful service life. Data is available from multiple sources on appliance service lives and energy use, along with appliance costs and incentives needed to upgrade to a more efficient appliance. This data allows planners to determine the likely benefits and costs of various energy efficiency programs.

Considerable thought was given to accountability and programs implemented in other states were reviewed to assure that the programs will provide the anticipated results. I anticipate that the Plan's energy efficiency recommendation will result in the need for three or four more staff at the PSC. These staff would play a major role in oversight and assuring the program meets its goals.

Results from programs undertaken in other states have shown that energy efficiency can play an important role, along with other resource options, in meeting a state's electric energy needs as part of a least cost/least risk electric resource portfolio. Energy efficiency has, and continues to play a major role for some states in meeting their electric energy requirements.

131. Recently, an increase in market prices for gasoline resulted in a significant drop in demand which caused prices to moderate. Do you agree that perhaps the best incentive to conserve on electric use comes from high prices?

In the short term, demand for electricity is considered to be highly inelastic due in part, perhaps, to the way the product is priced. At this time, increasing the price of electricity would likely create a burden to Michigan ratepayers, residential and businesses, without achieving significant energy savings.

132. How much consideration did you give to pricing retail electricity based on time of use as an alternative to a centralized state efficiency program?

This option was given considerable discussion and analysis. The Plan recommends that the Commission commence a collaborative involving one or more real-time pricing pilots to assess the value of this option to help manage electric demand. I view time-of-use rates as a compliment to an energy efficiency program because the primary goal of such rates is to shift load from peak to off-peak periods, but not necessarily save on total energy use.

133. **The Plan recommends a major statewide efficiency program; however, the 21st Century Energy Plan was focused on the electric industry only. Is it your intention that the efficiency program be limited to electric energy or would natural gas be included as well? Should gas be included?**

The Plan recommends an energy efficiency program for electricity. I would not object to a larger program that included natural gas as well. There are, in fact, particular cost advantages that can be obtained from a combined gas and electric efficiency program. For example, energy audits, are a foundational service provided to customers by energy efficiency programs, but have a necessarily high overhead. A combined gas and electric program, however, can spread that cost over combined gas and electric energy savings, resulting in a much sooner payback of the audit expense. In addition, some new technology appliances, such as high efficiency furnaces that incorporate variable speed blowers can result in significant gas and electric savings.

134. **Once a statewide efficiency program is established, there will be a permanent new agency with a vested interest in preserving its status. How can we be sure that this agency can be phased out if it is no longer needed, particularly if it gets harder and harder to achieve efficiency savings as the best and most cost effective measures are implemented early**?

Program evaluations and assessments will be made public and will be provided to the legislature on an annual basis. Both the Commission and the legislature have the opportunity to review the program on a regular basis to assure that it is still effective. In addition, the energy efficiency administrator will operate within the constraints of a performance based contract having a term that is limited to between three and five years, at which time the contract would be re-bid through a competitive process. If it was determined that the program was no longer needed, the program could be phased out at the conclusion of such contract period.

135. **The Plan recommends new legislation to authorize the Commission to order utilities to engage in active load management programs. As the Plan notes, however, some utilities are already engaged in such programs. Why do we need new legislation and mandates in this area since it would be in the best interest of a utility to propose reasonable programs?**

Despite the emergence of the Midwest market, hourly LMPs and the opportunity to lower power supply costs in those markets through use of load management, incumbent utilities have not seemed interested in expanding existing programs. Hopefully, the IRP process contemplated by the Plan and continued participation in the wholesale markets will encourage expansion of load management programs. However, this has not yet occurred and, as a back stop, authorizing the Commission to require this type of programming could help lower power supply costs.

136. **The Plan also recommends new legislation to mandate demand response programs if a pilot program demonstrates they are cost effective and in the public interest. This area requires the use of advanced metering technologies which are just beginning to come into the market. Is it premature to call for legislation without observing the results from wide spread adoption of advanced metering and allowing some voluntary experimentation in this area?**

Advanced metering technologies have already been deployed by some of the cooperatives in Michigan and by other utilities in the U.S. What is new is the ability to use the meters to signal real time electric prices. The Plan calls for experimenting with new meters to provide pricing information to customers in order to assess the real time price impact on customer usage. It is only after the results of these experiments are complete and available for public scrutiny that the Commission would consider expanding these programs. If the programs turned out to be ineffective, the Commission would not expand the programs. This seems more efficient than seeking legislation after the program results are in. Participation in any program by customers would be on a voluntary basis.

137. **The MPSC is an agency which has the primary function of determining reasonable utility rates in the absence of competition and regulating services. This Plan calls for major new responsibilities of the Commission, on top of those additional duties which accompanied Act 141. These include administration of a new IRP program, administration associated with the RPS and regulation and oversight regarding a major statewide efficiency program. What studies has the Commission performed to address the additional costs of this new regulation?**

The Commission has not conducted any such studies. However, most of the energy efficiency work will be undertaken by private sector firms, not state employees. The number of new employees needed for all components of the Plan should be six to nine.

138. **Does the MPSC have adequate staff and particularly personnel with expertise to handle all of these new functions?**

The MPSC has much of the expertise needed to monitor, administer, and implement the programs, but would require some additional personnel.

139. **What additional regulatory costs will need to be recovered through utility rates to expand the capability of the MPSC Staff?**

Please see response to question 137.

140. What is your position on the pre-funding of power plant construction before the plant is "used and useful?"

I do not favor pre-funding a power plant before it is used and useful. I do recommend that the Commission leave open the possibility of allowing recovery or some or all of the financing costs incurred during construction. This would represent an extension of the Commission's current treatment of pollution control expenses.

141. If this state's ratepayers have already paid for a portion of the plant before it begins operation won't that mean that the plant will be put in rate base without any meaningful review?

The plant's construction costs must go through a prudency review prior to inclusion in rates, as is the case presently.

142. Why should utility shareholders assume no risk in the building of a new power plant, and still receive a high, guaranteed rate of return?

The shareholder would need to assume risk in building a new power plant, since only the issue of the need for the plant will have been resolved. Only the financing costs incurred during construction would be eligible for recovery during construction, and the Commission may not allow recovery of those costs. Thus most of the plant's cost would still be subject to a prudency review.

I would also note that allowed utility rates of return are typically comparatively low.

143. It has been suggested that Michigan's industrial electric rates are still the highest in the Midwest. What are you doing to deskew electric rates that are causing Michigan Manufacturers to pay at least an additional $120 million a year of energy costs? What is your timetable on de- skewing rates?

Detroit Edison and Consumers Energy have recently filed rate cases with the Commission that include requests to deskew rates. Although I cannot discuss matters pending before the Commission, I anticipate this issue will be addressed in these cases.

144. All contracts with the State of Michigan must be competitively bid if they are over $25,000. Yet for a new baseload power plant that will cost in the billions of dollars, there would be no competitive bidding. This seems like throwing away hundreds of millions of dollars of potential savings for something that is routinely done both in the private sector, and currently by the state. Why do you think competitive bidding is the wrong way to proceed?

As noted in my responses to questions 54 and 72, the disadvantages of competitive bidding are many, and advantages seem limited as illusory. For example, one of the chief advantages of competitive bidding cited by proponents is lowered expected costs because of the use of large amounts of debt to finance IPP plants. However, as noted pages 47 and 48 of Appendix I, this purported advantage is an illusion. The use of large concentrations of debt can only occur because an IPP makes use of the utilities balance sheet to secure the debt. The risk of the IPP's debt is transferred to the utility through the PPA and raises the utility's cost of capital, or rate of return. This raises the utility's revenue requirement on all of its other investments and raises rates to ratepayers. Although the IPP gives the appearance of building a plant for a lower cost, in reality it costs more by raising the revenue requirement on the utility's other assets.

Once customers pay the capital costs of a utility's power plant, the plant will continue providing power and customers will not need to continue making capital cost payments. However, once ratepayers pay for an IPP plant, the ratepayers must continue making capital cost payments at market rates or the power will flow elsewhere. Thus ratepayers may be required to pay for an IPP plant more than once.

Additional reasons for not making bidding mandatory can be found on pages 19-21 of the Plan and 46 to 50 of Appendix I. I should note, however, that competitive bidding for large baseload power plants can be very complex, with the need to tackle issues that extend for decades, like fuel supply or air emissions standards. Uncertainty over interconnection costs make it nearly impossible to compare bids. It's no surprise that most states do not require competitive bidding.

Nevertheless, if an IPP believes that it can build a plant for a lower cost than a utility, it is free to do so in Michigan and to sell its power to AES firms, to large industrial customers, or directly to the wholesale market. AES firms and IPPs are free to jointly build and operate a plant and compete against incumbent utilities for customers. This business opportunity should serve as the best check on utility construction costs.

145. How can open access be a deterrent to cost overruns when a Certificate of Need has been issued before the extent of the overruns is known which customers leaving the system must pay for the overruns?

There is no easy way to assign cost responsibility in Michigan's hybrid market. However, utilities in Michigan have already experienced the revenue loss of hundreds of millions of dollars through customers leaving bundled service for choice. This experience, along with the threat that a large migration to choice could occur again, should discipline the utility's construction program. The utilities will have a burden to explain to their customers that they have the capability to manage a major construction project. If they can do that, and the customer remains with the utility, then the plant will be assumed to be constructed for those customers. On the other hand, some customers have expressed doubts about a utility's ability to successfully complete a major construction project at a reasonable cost. Some of these participants have indicated that they would prefer to have anyone but the incumbent utility build a new plant. Those customers who doubt that incumbent utilities have the ability to successfully construct a plant have an opportunity to leave before being committed to pay for the plant.

146. You recommend that rates be raised by $68 -$110 million per year be collected from customers to pay for an energy efficiency program. Does that include customers from all electric utilities or only selected utilities? Who gets an exemption?

All electric load serving entities; no load serving entity would get an exemption.

147. Are Michigan utilities currently financing billions of dollars to pay for equipment to meet Clean Air Act requirements? Current customers are free to leave aren't they?

Yes, customers are free to leave. However, keep in mind that the current Clean Air Amendment (CAA) expenditures are spread over thousands of megawatts of generation involving multiple units and millions of megawatts of generation annually. Moreover, these generating units are low cost base load units that have been depreciated for ratemaking purposes. The impact on any plant should not cause the plant to become significantly more expensive.

148. Would you agree that transmission plays a critical role in meeting our current and future energy needs? Why is transmission in the Lower Peninsula reduced to a footnote in the Plan? You speak more to transmission in the Upper Peninsula than the Lower Peninsula, Why? Isn't the transmission system in the Upper Peninsula also FERC regulated (through American Transmission Company)?

I would agree that transmission plays an indispensable role in meeting electric energy needs. Considerable time and effort was devoted to assessing current transmission capability, options to increase transmission import capability, and the value of increased transmission in both the Plan and the CNF. Please refer to pages 12-35 of Appendix I, which describes the modeling program including the role of transmission, and 72 to 77 of Appendix II, which describes transmission capability and options to increase transmission capability. Also see Appendix G of the CNF, which served as the basis for the transmission analysis included in the Plan.

Transmission was used as an option to provide access to wholesale electricity markets outside of Michigan (Upper and Lower Peninsula). Market price estimates were made for all control areas of the eastern interconnection over the entire planning period in order to evaluate the transmission option. For the Lower Peninsula, the model result indicated that it was less expensive to build base load generation in Michigan than to build additional transmission and then purchase power in the wholesale markets at the forecast market prices.

Additionally, the Upper Peninsula's reliability is heavily dependent on transmission upgrades. For a further discussion of this issue, please see pages 77-81 of Appendix II.

Transmission plays a far more important role in supplying energy and capacity for reliability in the Upper Peninsula than in the Lower Peninsula.

149. You refer to the "vagaries of the MISO market" in the Plan, yet in the MPSC's 2006 Status of Electric Competition in Michigan report, you discuss how, "The Midwest Independent System Operator (MISO) maintained reliable electric service during unexpected outages of generating plants and extremely high summer temperatures and peak loads." Do you agree that if it weren't for MISO during the peak days of summer 2006, the lights would have or could have gone out in Michigan?

Possibly. The reference here is to the volatile nature of the wholesale market prices, not the reliability function. Major weather changes, demand changes, or fuel cost changes can cause market prices to jump quickly, or short periods or for prolonged periods. Relying on the market exposes ratepayers to considerable risks. MISO manages the Midwest's wholesale market prices and also serves as the regional reliability coordinator.

MISO can perform the regional reliability function whether or not it also manages the Midwest day ahead and hour ahead wholesale markets.

150. Do you know why we had so many unexpected plant outages here in Michigan? What "vagaries" are you referring to?

See response to question 149. Without knowing what period of time is being referred to, I cannot respond to the question regarding plant outages.

151. The Plan references $400.00/mW hour rate for energy obtained through the MISO process at time of system peak. Does that price reflect normal prices in the MISO market or are charges of that size generally reflective of the spot market, like buying an airline ticket on the day you have to travel — if you planned in advance would the price be cheaper?

The $400/Mwh is a LMP, these prices vary by hour and must be paid by all customers at that pricing node, since <u>all power must be purchased through this wholesale market</u> at LMPs that vary at five minute intervals. These high prices can be seen in nearly any month, but not for prolonged periods. Owning your own generation, especially base load, or having a robust load management program is the best way to avoid these costs. Owning generation helps avoid these volatile prices because the amount paid by load at pricing nodes should be nearly equal to the amount received by generators. Load management helps avoid the high prices, because a load serving entity's load can be reduced during these periods.

152. **How often do Michigan's utilities buy and sell energy in the wholesale market (through MISO)? Is it every day, once per month, once per year? And, why do they buy and sell energy in the market? Is it to get access to cheaper generation, rather than running a more expensive plant that perhaps they own themselves? Do you agree they need to transport this cheaper energy over the transmission grid to deliver to their customers? Would you agree or support the notion that utilities should continue to buy and sell energy in the wholesale market in order to get access to the cheapest sources of generation? And, don't you need a robust transmission grid to ensure yourself that the customer is always getting access to the cheapest source of generation, otherwise they may be held captive to more expensive generation?**

All electric energy provided by jurisdictional utilities is bought and sold in wholesale markets at the appropriate commercial or generator nodes and at LMPs. MISO uses security constrained unit dispatch to provide power from all designated network resources (generators) to all loads across the MISO footprint. Generally, the dispatch observes transmission limits and provides power from units based upon low to high priced bids.

Transmission can provide access to lower cost power, either based upon the MISO day ahead or hour ahead dispatch, or based upon long-term contracts.

I would expect utilities to continue to search for and acquire the lowest cost power, including power in wholesale markets. In fact, this was so important, considerable effort was made in the Plan to identify a major transmission upgrade and assess its value in allowing access to wholesale markets.

I support a robust transmission grid.

153. **Generally speaking, would you agree that higher energy costs usually occur when utilities have to go on the open market during periods of peak demand, or to MISO, to obtain energy? Isn't it true that when utilities go to the market for whatever reason, that utilities flow those costs through to ratepayers through their PSCR? How do you reconcile the flow through of energy costs with the PSCR, as opposed to poor maintenance and performance of a generating unit that is in rate base, and being recovered from ratepayers, when it is not running?**

Yes, generally energy costs are higher during peak periods and these costs are generally flowed through to ratepayers, if prudently incurred. The issue of whether a utility's purchases are prudent is examined in the annual PSCR reconciliation proceeding at the Commission. Generally, there is a large data set of unit performances available for all jurisdictional generating units. From this data, it is possible to identify units that are experiencing anomalous performance and requiring the utility to rely on market purchases. This performance can then be examined to determine whether a cost disallowance is appropriate.

The wholesale markets should provide an incentive for utilities to reduce unit outages, especially for low cost base load units, since all excess generation can be sold into the wholesale markets. There is no incentive for the utility to cause or allow plants to be unavailable when this dispatch cost is lower than the LMP.

154. Would you agree that transmission provides reliability and generation (baseload, nuclear, renewables) provides energy? If you agree, then we don't necessarily protect against another blackout, or "brown-outs", with more generation, but really with a robust, transmission grid?

Generation provides energy, reactive power, and capacity, which is needed for reliability. Likewise, transmission provides access to capacity and energy. Both play important roles in assuring reliability. Transmission cannot provide energy to a sink if there is insufficient generation at the source. A robust transmission grid is only a part of the solution. Transmission must be coupled with generation, or coupled with energy efficiency and demand side alternatives in order to provide reliability.

155. Have you thought about implementing performance standards for generators? In other words if bad decisions are made that takes a generator offline and out of service and there are cost implications to ratepayers as a result of those bad decisions, why should a utility get to recover those added costs from customers when they go to the spot market for energy, when it was the utility that caused the problem in the first place?

This issue is reviewed in the annual PSCR reconciliation proceedings at the Commission. Disallowances are imposed when a utility exercises bad judgment or is imprudent in taking a generator offline or prolonging a unit outage.

Mandatory enforceable planning reserves for entities within Michigan, if enacted by legislation, would help to minimize the risks of exposure to higher more volatile energy market prices in the event of an unavoidable forced outage.

156. If you are the CEO of a regulated electric utility under the current regulatory structure, what are the two ways in which you can improve your bottom line, for the benefit of shareholders? (Invest in rate base and earn a return on equity, and cut expenses, particularly maintenance expenses). What mechanisms are in place to ensure that utilities don't cut maintenance expenses for the benefit of shareholders and to the detriment of customers? Have you given any thought to an alternative regulatory construct that incentives a utility to do the proper maintenance, and prevents it from cutting maintenance expenses to meet shareholder returns?

Any cut in maintenance expenses would be picked up in the utility's next rate case and serve to lower rates. In several recent rate proceedings the Commission has provided for recovery of forestry (tree-trimming) and nuclear maintenance expense increases under strict reporting guidelines and refund requirements. This assumes money provided for maintenance expenditures are actually spent on needed projects or the money is refunded to ratepayers. The reporting requirements provide an opportunity for periodic reviews to insure that program expenditures are prudent and cost effective. Pursuant to the Commission's Show Cause case, Detroit Edison's current rate filing includes an independent consultant's report on utility cost benchmarking and performance standards that will be reviewed by all parties in that proceeding. Also, the Commission has adopted distribution performance measures that utilities are required to adhere to. Failure to adhere to the performance standards can result in penalties to the utility. The Commission and staff have explored performance based ratemaking methods in the past and have adopted some performance standards. I remain open to considering performance based ratemaking proposals.

157. Is it true that all regulated utilities make money by earning a ROE on invested rate base? Is it true that Detroit Edison and Consumers Energy would have significantly reduced balance sheets as a result of the securitization of their respective nuclear plants? Is it feasible that one way for these utilities to increase their returns to shareholders is by investing in rate base?

It is true that earning to shareholders comes from the allowed rate of return on rate base and that securitization reduced each utility's rate base. Investing in rate base will serve to increase returns to shareholders.

Questions from Senator Kuipers

1. **The 21 Century Energy Plan calls for a number of mandated programs where the cost would be passed on to customers. With Michigan's manufacturing sector in veritable depression, do you believe it is a good idea to pass these additional mandate costs on to commercial and industrial customers?**

   As demonstrated by two years of modeling in the CNF and Plan, these programs, on a going forward basis, will lower the cost of providing electricity compared to Michigan's current electric utility policy.

   Please note also that large businesses can and are expected to opt out of energy efficiency costs, and RPS off-ramps are provided where necessary to prevent costs from rising to unreasonable levels.

2. **What are your views on competitive bidding for new power plants?**

   See response to Senator Patterson's questions 54 and 72.

3. **It appears the utilities want to change PA 141, and move away from a competitive marketplace. If we were to change the Act and go back to a regulated system, would you support having DTE and Consumers give back the $1.8 billion in securitization and stranded costs that they received upfront as a condition for going to a competitive system?**

   Although PA 141 was enacted in 2000, no stranded cost recovery was allowed until 2004 and the Commission has indicated that it believes that stranded costs will no longer be an issue now that rate caps have expired. Securitization of capital costs related to Fermi II and Palisades did not accelerate the recovery of these costs from ratepayers. Securitization was a refinancing of the plants' capital costs which resulted in removal of the plants from each utility's rate base. The proceeds of the refinancing were used to payoff debt and redeem common stock of each company, or refinance the plants with higher rated debt. Ratepayers have received and continue to receive power produced by each plant, at each plant's cost of production, so it is unclear why the securitization payments would be returned to ratepayers. Securitization payments are simply payments made in the place of traditional rate base recovery through depreciation expense.

   The savings created by securitization were passed on to bundled customers in the form of a 5% rate cut for up to six years, to low income customers and for energy efficiency through the Low Income and Energy Efficiency Fund, and to AES customers through funding of a 5% rate cut and a securitization offset so that AES customers did not have to pay securitization charges.

4. **This plan recommends new legislation that creates the Michigan Energy Efficiency Program (MEEP), a statewide energy efficiency program under the authority, oversight, and guidance of the Commission, applicable to all load serving entities; and the Michigan Energy Efficiency Fund (MEEF), a statewide public benefits fund created within the Department of Treasury and administered by the Commission.**

a. **The creation of this new customer charge to generate $100,000,000 a year to run energy efficiency programs looks a lot like last year's SB 334. As I remember this committee refused to pass a version that would have created a customer charge to run energy efficiency programs. What makes this bill one that we should pass?**

Extensive analysis and modeling have demonstrated that well designed energy efficiency programs can produce substantial energy savings, at a cost less than the cost of new generating plants. Substantial evidence from across the country and growing evidence here in Michigan demonstrate the value of energy efficiency programs. This information provides the basis for moving forward with an energy efficiency program. If the Senate is not inclined to adopt the scope of programming recommended by the Plan, it is my hope that the data and analysis performed to date will encourage authorization of programming that can be expanded over time as the results of energy efficiency programming here in Michigan become better known

b. **This new proposal would create a permanent new bureaucracy to run energy efficiency programs. How does this proposal to create a permanent new bureaucracy make this a less objectionable proposal than last years SB 334?**

The adoption of this bill would require only three or four new state employees. The program is designed to make use of private sector firms to devise and undertake marketing activity, deliver services and provide educational programs. The role of the Commission and its staff would be to set program goals, monitor program performance, audit and assure compliance with program rules.

c. **What kinds of programs would this new program operate?**

See response to Senator Patterson's question 20.

d. **Would this new program supplant the existing energy efficiency programs created by the MPSC in Detroit Edison and Consumers energy rate cases?**

This program would be handled separately from current Detroit Edison and Consumers low-income programs, (LIEEF – Low Income Energy Efficiency Fund) which are principally intended to assist with energy payments. A minor portion of current LIEEF funding is used for low-income weatherization. Low income customers would be encouraged to participate in the new program, thus current low-income programs may need to be adjusted to properly complement a new statewide energy efficiency program.

5. **The Energy Plan suggested that the Commission may grant or deny a Certificate of Need and, if granted, the need for the plant cannot be challenged in a future proceeding**

   a. **Why would the State of Michigan want to lock its citizens into an irreversible decision that will likely cost customers several billion dollars over the next thirty years?**

   Several billion dollars would seem too high for the cost of a new generating plant or even a couple of plants. Nevertheless, the recommendation for a certificate of need is to palliate the effect of provisions in PA 141 that allow customers to leave utility service and return again later. A part of the traditional used and useful test that the Commission has used to determine whether the capital costs of a new generating plant will be permitted in a utility's rate base is whether the plant is needed or not. The movement of customers to and from customer choice may cause a new plant to seem reasonable at one time, and then appear to be unneeded if customers migrate to choice suppliers. A utility attempting to build a new generating plant will be uncertain of its future customer base, and, therefore, the need for a new plant, even though it may be necessary when construction begins. This places recovery of a plant at risk, and makes it difficult to arrange reasonable financing.

   Although the need for a new plant would be resolved by issuance of certificate of need, ratepayers would still be protected from excessive construction costs through a prudency review when the plant became operational.

   If steps are not taken to ensure that additional baseload plants are built in the next 10 to 20 years then, as seen in the Plan, Appendix I, page 23, the Combustion Turbine only cases, the cost of providing electricity will be much greater than it needs to be. Doing nothing would be approximately $2 billion dollars more costly than building needed baseload plants, on a present value basis.

   b. **Essentially, once the certificate has been granted to the utility, there would be no ability for the Commission or the State of Michigan to question the prudence of the power plant or the costs of such a facility, correct?**

   No. The actual cost of the plant would be subject to a prudence review. Only the need for the plant would be resolved by the certificate.

6. **The Report states that customers returning to full service will receive regulated rates two years from the date of notification that they wish to return. The utility will use its best efforts to provide electric service at market rates during that two- year time period. Customers leaving full service after a Certificate of Need has been granted will carry surcharge with them for the new plant.**

   a. **Based on your argument, all customers benefit from the construction of a new power plant, correct?**

   All customers in reasonable proximity should benefit.

   b. **By that logic, should all Michigan electric consumers pay for the new power plant? That is, if DTE builds a new power plant should the customers of Consumers Energy and the municipal and co-ops also pay for the new power plant?**

   As a practical matter, benefits are concentrated in the utility's service territory. For example, a new base load unit would likely cause LMPs to decline near the generator node, but not across the entire state.

7. **The Report states: "The ability of customers to move between the regulated and competitive markets creates permanent uncertainty about the size of the customer base for both utilities and AESs. This uncertainty makes planning and financing of expensive, long-lived base load generating units very difficult. Because of their obligation to serve all potential customers in their territory, the utilities bear the responsibility to plan (and construct) for this load, despite the fact that customers may migrate at any time from the utilities' regulated rates to the competitive sector's market rates."**

   a. **What facts did you rely on to reach your conclusion that the uncertainty makes planning and financing of expensive, long-lived base load generating units very difficult?**

   This has been widely observed throughout the United States, especially for base load power plants. For example, PJM has recently adopted a mandatory capacity market to assure a revenue stream for generating units. Ratepayers are required to purchase energy at market prices and also, separately, purchase capacity at rates partly determined by PJM management. The goal of the second, capacity market, is to assure a revenue stream for prospective, new generating units.

   On the other hand, base load plants are being built in states that have continued with traditional regulation like Wisconsin and Iowa.. Traditional regulation provides the revenue stream needed to finance plants on reasonable terms.

   Discussions with participants in both the CNF and the Plan have confirmed this conclusion. You may note that customer choice coalition members, IPPs, and industrial customers proposed their own determination of need proceeding at the Commission similar to the certificate of need process for the Plan.

8. The report recommends that all load serving entities will be required to maintain planning reserves and the Commission will be authored to penalize entities that do not meet the reserve requirement.

a. Isn't the Midwest Independent System Operator (MISO) currently addressing resource adequacy on a regional basis?

Reliability standards are promulgated by Reliability First, the regional NERC member, while MISO is the regional reliability coordinator. However, it appears that neither Reliability First or MISO can enforce planning reserve standards. The Energy Policy Act of 2005 indicates that resource adequacy policy such as planning reserves shall be left to the states for enforcement. While we are prepared to adhere to the reliability standards promulgated by Reliability First, we must have the authority to require that the standards are actually adhered to by all Michigan load-serving entities. Therefore, this Plan recommendation is important to maintain electric reliability in Michigan.

9. How much have DTE's rates gone up annually over the last 3 years, including fuel costs?

See Attachment 3.

Questions from Senator Brown

1. **The 21st Century Plan proposes an up front approval process for new generation. It is clear how it applies to new generation. It is unclear how alternative transmission solutions would be considered at the same time. Since there is already a up front approval process for new transmission projects, would it be sensible to merge the two processes so that the PSC can determine the advisability of alternative transmission and generation solutions up front at the same time?**

   The Plan's recommendation for an IRP would require the simultaneous assessment of generation and transmission options, prior to a determination that additional generation is needed. Please see response to Senator Patterson's questions 2, 3, 4, and 5 for additional details.

2. **Under the 21st Century model the PSC first determines need. Once need has been approved it cannot be revoked. After need has been approved, a utility is to competitively bid the engineering, construction and procurement aspects of a new plant project and construct the plant. How would the PSC balance and compare the costs of alternative generating and transmission projects during the "need determination" if the generating costs have not yet been determined?**

   Estimates for generation costs and transmission costs must be supplied by the filing utility and these costs would be subject to public scrutiny. Participants to the IRP filing would be allowed to question estimated costs and provide any information deemed pertinent to assessing resource costs. Further, while the need for the plant may not be challenged at a later date, the cost of the plant could be. Therefore, if the utility supplies one cost for a new plant during the IRP but another after the engineer, procure, construct phase (EPC), it may be in jeopardy of a disallowance.

   Also, Commission staff would review and prepare cost estimates and provide guidance and independent analyses to the Commission in an IRP case.

3. **The PSC recommends that a utility only be allowed to use its current renewable resources to satisfy the first 3% of a renewable portfolio standard (RPS), while new renewable resources must be used to satisfy the next 7%. However, it is my understanding that some Michigan utilities already have sufficient renewable resources to satisfy a RPS in excess of 3%. Wouldn't this requirement place an undue burden on utilities that have already made significant renewable investments? Wouldn't this additional burden be passed on to customers?**

   One goal of the plan was to encourage the development of new Michigan based renewable energy facilities and do so in a fair manner. Allowing some utilities to avoid contributing to new renewable resource needs because they are in possession of 50 or 60 year old hydro facilities seems unfair. While the Plan recognizes that it is impossible to satisfy all utilities with one plan, allowing up to 3% of existing renewable to count toward the RPS is a reasonable compromise. It should also be noted that a utility that believes adherence to the RPS would cause hardship could request a waiver.

4. **How will the limitations on the use of out-of-state renewable energy credit (REC) programs in complying with the RPS affect companies that operate in multiple states?**

For their operations in Michigan, they would be subject to the same regulations as Michigan-only utilities.

Questions from Senator Thomas

1. **The 21st Century Energy Plan lays out a comprehensive plan for energy efficiency, including looking at revision of building codes to obtain more efficiencies. These recommendations make sense from a public policy standpoint, especially in light of the growing body of evidence suggesting the current and future effects of climate change on our environment. However, when taking into consideration the realities of Michigan's existing infrastructure and institutional make-up, how will such a program relate to low- income housing programs which attempt (with limited state, federal and non-profit resources) to make housing available to low-income individuals at the lowest cost possible? The delicate balance of public support and private investment make low- income housing a very difficult project to undertake. Is it possible that stricter building codes could make such programs cost prohibitive for public and private investment?**

   Because of increasingly high and volatile energy costs, housing affordability is strongly related to energy costs. In particular, low income individuals are hard hit by high energy prices. Energy efficient housing projects should, because of greater affordability, have increased subscription rates and consequent reduced investment risk. However, only if new standards are cost effective, will improved construction standards reduce the net monthly housing cost to low income individuals. In order to ensure that any new standards are cost effective, I am recommending that the Governor issue an executive directive instructing the Department of Labor and Economic Growth to commence a Michigan Energy Efficiency Construction Standards Collaborative having broad participation from interested parties. The impact of improved standards on investments in low-income housing projects can be specifically addressed by the collaborative.

2. **The 21st Century Energy Plan is a comprehensive assessment of the electric energy needs of Michigan in the short- and long-term, and provides a valuable record of how we got to this point and where we need to go. The comprehensive nature of the plan lends itself to reflection on the successes and effectiveness of PA 1141 of 2000, legislation which created the framework for Michigan's electricity market since that time. In light of our present energy situation, where financing the construction of new base load electric generation is virtually impossible, what would be the benefits of returning to a fully-regulated market structure?**

   I believe it would allow the construction of new baseload generating plants on more reasonable terms. It would also likely serve to keep our rates lower and more stable, as we have seen the largest increases in electricity rates in deregulated states.

Questions from Senator Olshove

1. **In addition to ensuring that energy capacity needs are met in the coming years, do the recommendations in the 21st Century Energy Plan provide for increased reliability, and if so, how?**

   The recommendations help ensure that reliability is maintained in a manner that lowers cost below what it would be without the Plan's recommendations and helps manage future industry risks. It does this by explicitly forecasting energy and demand needs, determining how much transmission and generation will be available to meet the forecast need, and then assessing which resource options are available to satisfy the shortfall in generation and transmission resources, at the lowest costs, while providing flexibility to manage future risks.

   Granting authority to the PSC to enforce planning reserve requirements across all load-serving entities in Michigan will make great strides toward ensuring long-term reliability within this state. Also, the major recommendations to provide an energy efficiency resource acquisition program and a mandatory RPS would serve to diversify the state's electricity resource base, both in terms of fuels and technologies.

2. **In addition to ensuring that energy capacity needs are met in the coming years, do the recommendations in the 21st Century Energy Plan provide for increased energy independence for Michigan, and if so, how?**

   Yes it does. It promotes an increased degree of energy independence by recommending a Michigan energy efficiency program, and Michigan load management program, and Michigan based renewable energy installations. These programs will help promote jobs in Michigan at the same time they reduce Michigan's need for out-of-state fuels.

3. **The 21st Century Energy Plan makes several recommendations regarding energy efficiency and renewable energy. Some critics maintain that these recommendations will result in higher energy costs. is this the case, or will these recommendations actually lower costs over time?**

   The Plan demonstrates that these resources will actually lower the costs of electric energy to Michigan over the next 20 years compared to Michigan's current policy. The Plan's results are consistent with actual experience in other states that have ongoing energy efficiency programs. Across the country, states have demonstrated energy efficiency programs that yield energy savings at an average of 3 cents per kWh. This is about one half of the expected cost of power from new baseload plants. Energy efficiency programs can also reduce the risk and level of future rate increases to Michigan consumers to pay for greenhouse gas controls that may be imposed by the federal government in the future.

4. **How will the recommendations regarding energy efficiency and renewable energy assist in job creation and Michigan's transition to a new, diversified economy?**

NextEnergy has recently investigated the impact of energy efficiency and renewable energy on Michigan's economy. The study resulted in estimates of 2,000 to 6,000 additional jobs and growth in gross state product after adoption of an RPS and an energy efficiency program. In addition, the State of Wisconsin, through legislation, recently expanded its statewide energy efficiency program to a level consistent with the level recommended by the Plan for Michigan. Wisconsin estimated that its statewide energy efficiency program will create about 2,000 new jobs directly related to the local energy efficiency industry. See also the answer to Senator Patterson's question 34.

5. **Does the 21st Century Energy Plan make allowance for electric generation from nuclear sources?**

Yes it does.

6. **What are positive aspects associated with nuclear power generation? Negative aspects?**

The positive aspects include near zero air emissions and stable energy production costs. The negative aspects include nuclear fuel disposal issues, uncertain capital costs and permitting schedules, and unit decommissioning.

7. **What kinds of environmental constraints exist relative to electric power generation using coal as a fuel source? Are further environmental constraints anticipated in the future?**

Non attainment status for criteria pollutants makes siting of new coal facilities in southeast Michigan problematic. It is anticipated that offsets for these pollutants are not available in sufficient amounts to permit construction and operation of a large, conventional coal fueled unit in the non attainment region of southeast Michigan.

The most likely future additional constraints will be greenhouse gas controls. Sixty percent of Michigan's generation comes from coal, and coal based generation results in approximately 70 million tons of CO_2 emissions annually in Michigan.

8. **How does the 21st Century Energy Plan set us up to meet current and future environmental constraints?**

The Plan recommends a balanced portfolio of resources including the implementation of a statewide energy efficiency program and expanded use of renewable energy options. Both of these resource options will reduce greenhouse gas emissions, along with future SO2, NOx, and mercury emissions.

9. **Of currently available coal-fired generation technology, is one type preferable to another?**

The Plan does not recommend one coal based technology over another.

10. **The 21st Century Energy Plan suggests implementation of rates that reflect different customer classes' true costs of service. This likely would mean an increase in rates for residential customers, who have historically been subsidized by other customer classes.**

In addition, the promise of PA 141 of 2000 was to allow customers of retail electric generation a choice in providers, a promise which has been virtually unmet for residential customers since that time. What benefits, if any, could residential electric customers expect from implementation of the 21st CEP?

Prices that are more stable and affordable in the future than they would be if Michigan's policy does not change, and protection from the rate increases associated with customer migration between Michigan's regulated and choice markets.

Questions from Senator Prusi

1. **The 21st CEP requires a Renewable Portfolio Standard of 10% by 2015. This is a laudable goal, and all utilities should be required to make every effort to meet it. However, the plan only gives a utility who is already utilizing renewable energy as part of its generation portfolio credit for up to 3% of its generation capacity, even if the actual number is much higher. For example, some utilities in the Upper Peninsula get as much as 30% of their generation capacity from hydro-electric sources. Should the various "off- ramps' recommended in the plan take account of these special circumstances?**

   I don't believe that the off ramps should be used to undermine the goals. The off ramps are intended to address rate impacts that may be a burden from compliance or hardships that may be encountered in attempting to comply with the RPS.

2. **Is the transmission system in the Upper Peninsula equipped to deliver additional renewable generation required by the 21st CEP, or would this represent an increased cost to UP consumers of electricity?**

   It depends on where the renewable energy may be sited. The transmission system in the U.P. is already being upgraded significantly, which should help to provide a system that can more easily accommodate more distributed, renewable energy resources. Under the current interconnection rules, the costs of any system upgrades necessary to accommodate new generators are split between the new generators and all users of the transmission system.

3. **American Transmission Company has announced transmission projects in the Upper Peninsula which would allow for increased electricity flow from Wisconsin, ostensibly increasing reliability. How could transmission upgrades of these types affect residential rates?**

   These upgrades should effect residential rates in two opposing ways. First, the increased transmission investment will tend to increase all rates in the U.P. Second, the expanded transmission should permit greater access to power from Wisconsin, and should cause U.P. LMPs to converge to lower Wisconsin LMPs.

Questions from Senator Birkholz

1. **Can you discuss P.A. 141 in the environment of Renewable Portfolio Standards?**

   The Plan is designed to maintain Michigan's hybrid market structure, but treat participants on a level playing field. To accomplish this, the Plan would require AES suppliers to meet the same RPS targets as incumbent utilities.

2. **In the 21 Century Energy Plan, there is much reference to increasing energy efficiency in Michigan. Since the demand for electricity is relatively inelastic, is such a focus on energy efficiency practical or worthwhile?**

   Yes, in fact it should be more important because demand is inelastic in the near term. If prices were highly elastic, price increases would drive down the demand for electricity. With inelastic prices, additional steps must be taken to assure reliability and meet energy needs.

   Energy efficiency has proven to be a viable and cost effective tool for meeting electricity needs in states that have continued energy efficiency programming. Certainly, energy efficiency is not the only resource that Michigan should use to meet its future needs, but it is an important component of a balanced resource mix that also includes renewable energy options, transmission upgrades, and traditional generation.

3. **Does a mandated RPS materially change the business model, or will global warming drive business eventually toward renewables given the advent of Carbon Taxes?**

   I don't believe that it will change the business model any more than PURPA changed the business model. Instead it should be viewed as a practical tool for managing future risks and costs. Future carbon taxes would have a large impact on electricity prices throughout this region of the country given its dependence on coal generation. Rather than waiting for greenhouse controls to be imposed, it makes more sense to anticipate and invest in resources that can minimize the impact of any future greenhouse gas controls.

4. **Michigan citizens want many things: more jobs, more residents moving to Michigan, lower fuel costs and clean air. How do we integrate all our wants into a single energy policy? Will a mandated renewable portfolio standard increase the costs to business?**

   The Plan's modeling phase included costs associated with clean air concerns, future fuel costs, and the overall costs of various resources. The Plan's policy proposals are the result of integrating those issues into one major modeling program.

   An RPS will lower the costs associated with electricity in Michigan over the long-run when compared to Michigan's current electric energy policy. As noted by the Plan, Michigan's current, de facto policy is anticipated to result in more reliance on wholesale markets, which have proven to be expensive and volatile. Adding renewable energy may cost more initially, but avoids future fuel cost escalations and potential greenhouse gas costs.

5. **Is deskewing an appropriate option to explore if an RPS is mandated?**

Deskewing should be pursued irrespective and independent of an RPS.

6. **Transmission throughout Michigan is a problem in many areas of our state. If an RPS is adopted, how should transmission issues be addressed?**

MISO has an established program for transmission upgrades and interconnections. The Commission has and will continue to complement MISO's transmission planning function by administering the Michigan Electric Transmission Line Certification Act, 1995 PA 30. ITC has been very effective at identifying needed transmission upgrades and including the upgrades in its planning proposals. We anticipate ITC will continue to play this vital, support role when an RPS is adopted.

7. **Was the 21 Century Energy Plan a consensus document?**

No. The Plan's process was designed to seek consensus as often as possible, but parties remained too far apart in virtually all areas for the Plan to reach any sort of a consensus. This was not unexpected.

8. **How can a heating assistance program be established and funded without the creation of a new bureaucracy?**

Heating assistance is now supplied through assistance from the federal government and programs adopted for Detroit Edison and Consumers Energy. The Plan does not recommend any changes to this current arrangement.

Questions from Senator Richardville

1. **What are your views on competitive bidding for new power plants? Your Plan seems to indicate that only incumbent utilities would be able to build new baseload plants.**

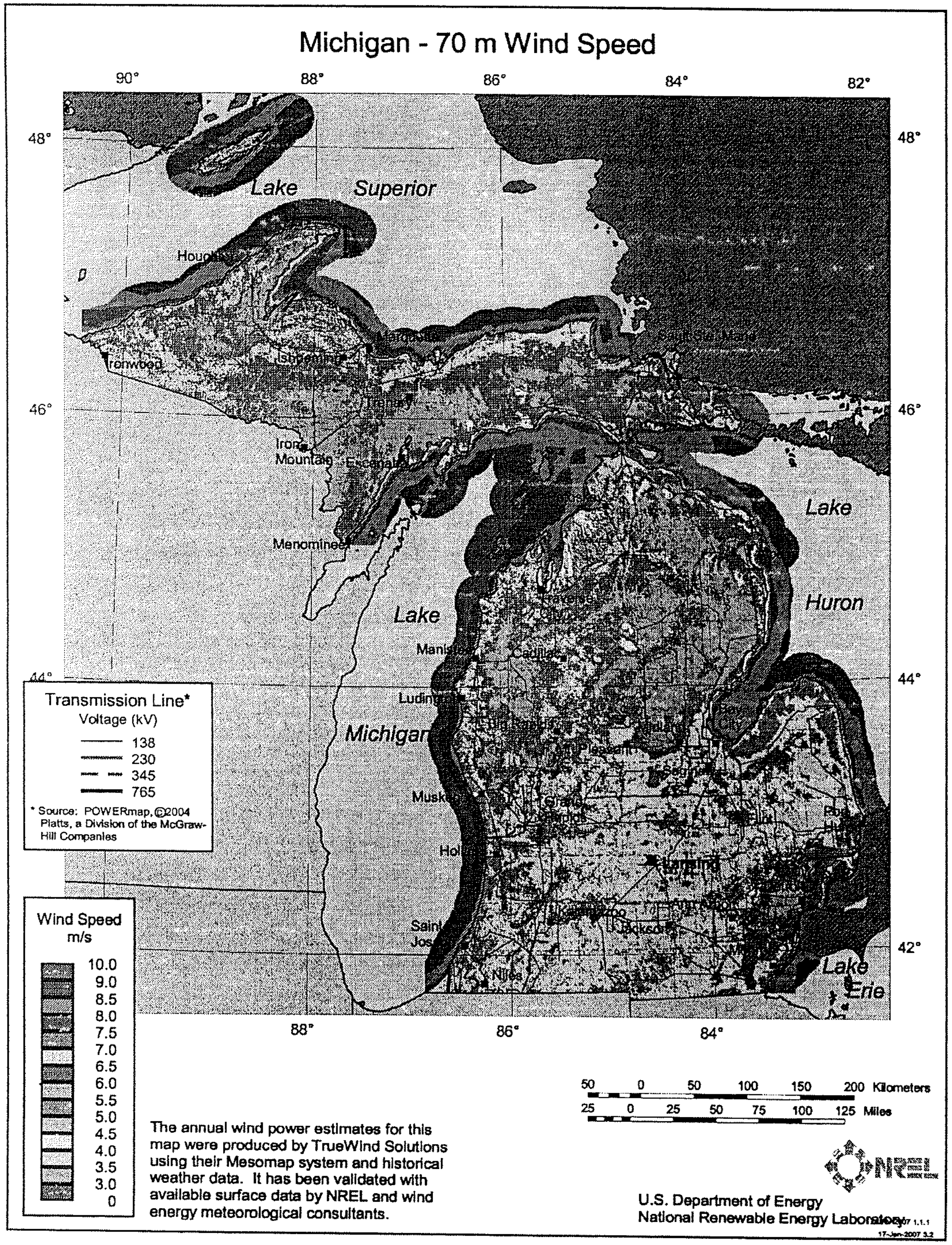
   The Plan does not require incumbent utilities to competitively bid for a new power plant through a PPA. Instead, it allows a utility to use competitive bidding or allows the utility to construct a plant itself, if the plant is needed. As noted previously, and on pages 19-21 in the Plan and pages 46-51 of Appendix I, respectively, the disadvantages of competitive bidding outweigh the benefits. I also note that most states do not require competitive bidding.

   Of course, non-utilities may construct power plants at any time without authorization from the MPSC.

2. **Do you see any problems since the state's utilities no longer own or operate transmission? That is, are the utilities likely to favor new generation over transmission since they will earn money on generation and not transmission?**

   This potential issue has been considered thoroughly in developing the Plan. Please see response to Senator Patterson's questions 2, 3, 4, and 5 for a detailed response. Adoption of the Plan's recommendations will assure that generation and transmission are simultaneously considered when determining whether additional generation is needed in Michigan.

Attachment 1



Wind Potential (12% Losses)

32-37% Capacity Factor: 14,000 MW

37-41% Capacity Factor: 1,000 MW

41-46% Capacity Factor: 100 MW

>46% Capacity Factor: <100 MW

Total: 15,000 MW

Michigan Wind Electric Potential (Installed Capacity)

We calculated a range of wind speeds and net capacity factors, assuming power losses of 12%, comparable to wind power classes 4 to 7. The wind speed ranges were used to estimate the windy land area and wind potential at map height of 70m.

Wind potential was estimated assuming 5 MW of installed wind capacity per square kilometer of available windy land. Capacity factors were based on the GE 1.5 MW 77-m turbine.

12% Power Losses

Net Capacity Factor (%)	Wind Speed meters/second	50-m Class (equivalent)
32 – 37	7.2 – 7.69	Class 4
37 – 41	7.7 – 8.29	Class 5
41 – 46	8.3 – 9.19	Class 6
> 46	>= 9.2	Class 7

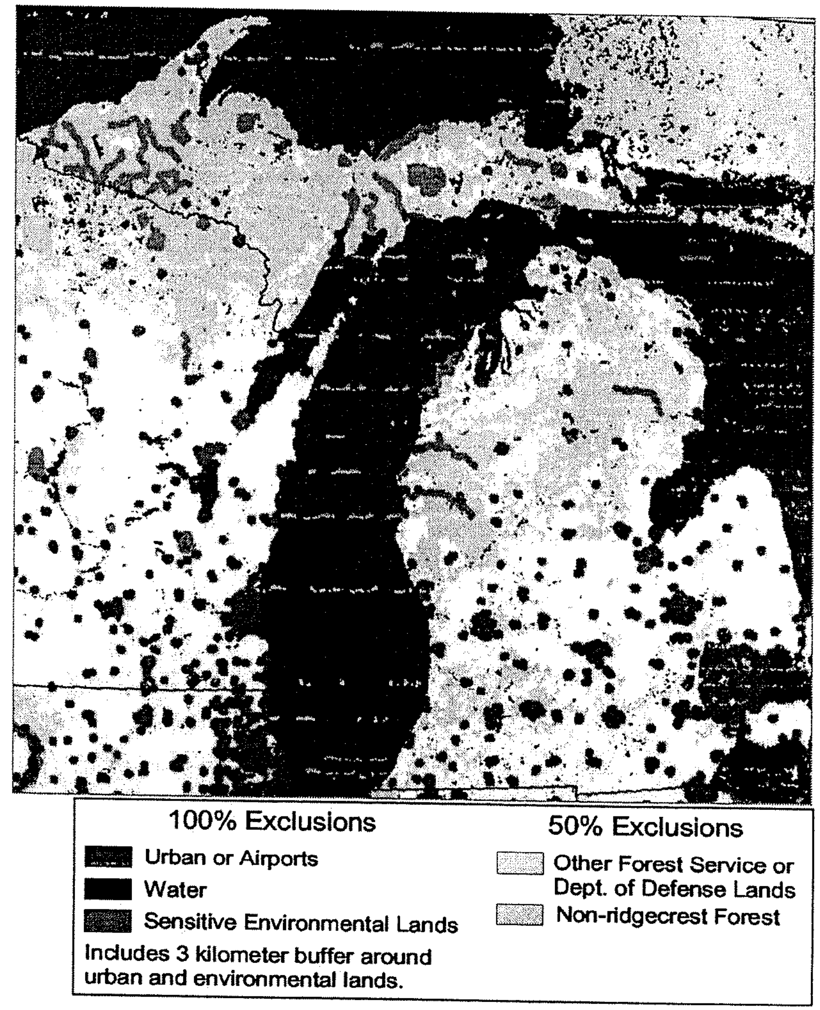
Estimates of Michigan Wind Electric Potential (Installed Capacity)

Assumes **12% Power Losses**

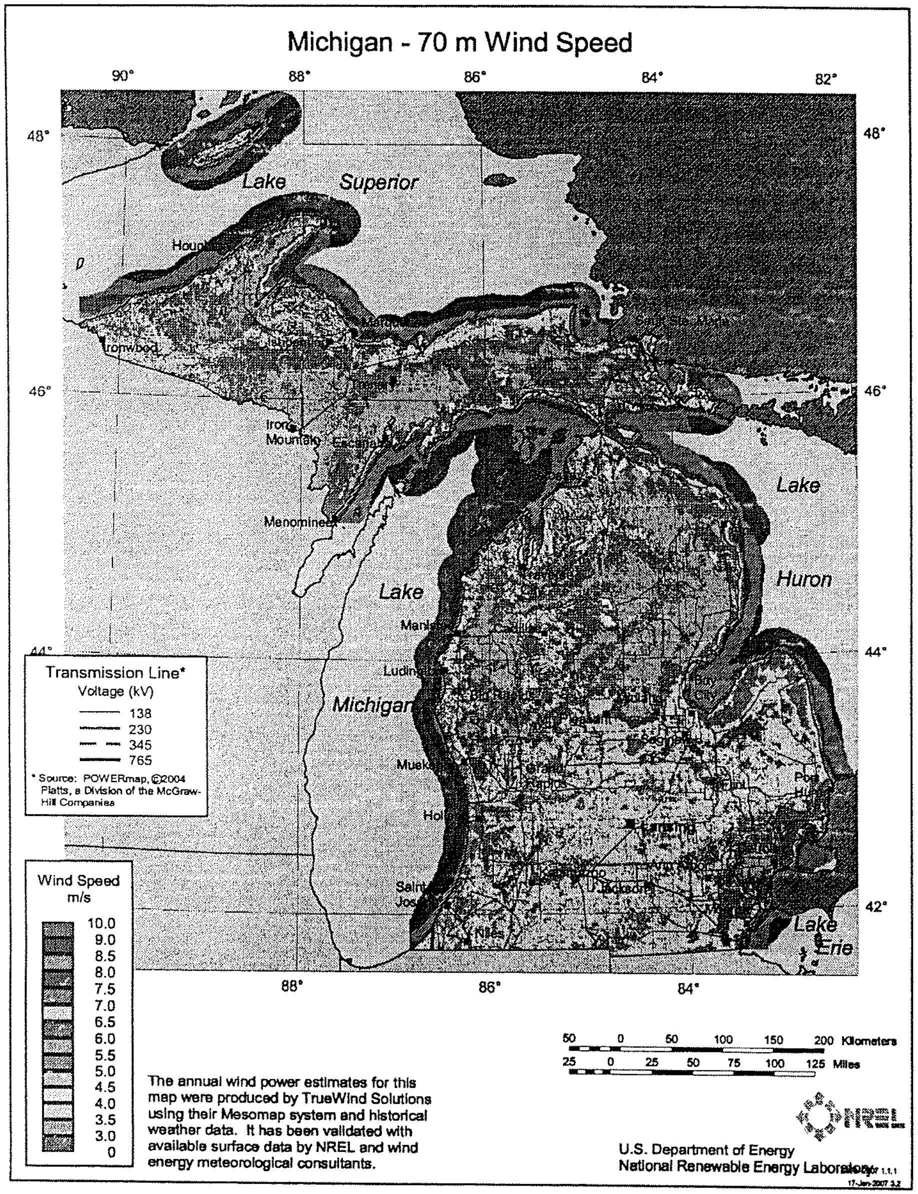
	70-m Height
Class 4	14,000 MW
Class 5	1,000 MW
Class 6	100 MW
Class 7	<100 MW
Total	**15,000 MW**

Areas Excluded from Developable Wind Potential

1) Potentially sensitive environmental lands:
   - National Park Service and Fish and Wildlife Service
   - Wildlife, wilderness, recreation areas, and other specially designated areas on federal land (predominantly Forest Service and BLM lands)
   - Some state and private environmental lands where data was available
   - Half of the remaining U.S. Forest Service and Department of Defense lands to represent current dedicated use of land
2) Potentially incompatible land use:
   - Urban areas, airports, wetlands and water bodies
   - Half of non-ridge crest forested areas
3) Other factors:
   - Slopes greater than 20%
   - A 3 kilometer area surrounding environmental and land use excluded areas (except water bodies)
   - Small, isolated class 3 and greater resource areas using a minimum density criteria



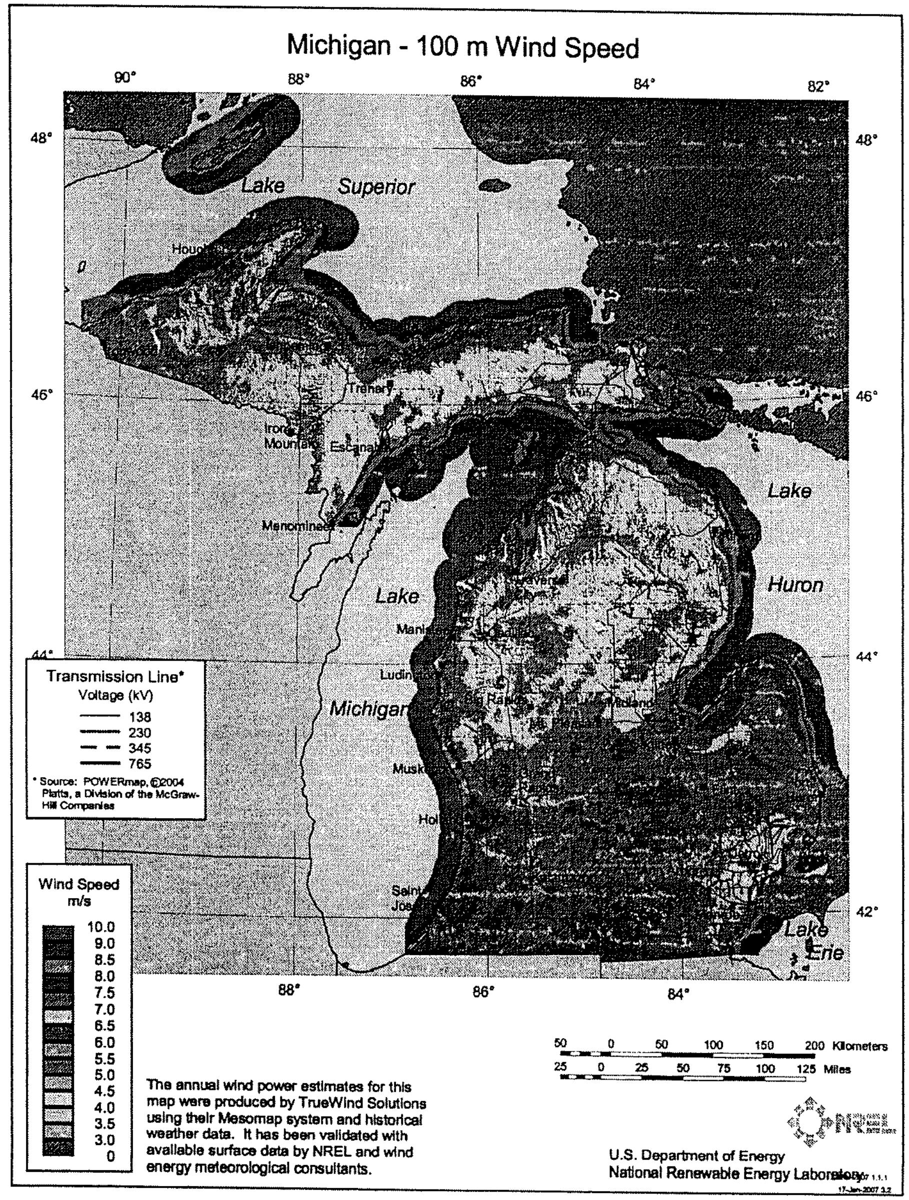
42% of the raw Class 4 and better lands excluded at 70 m (12% loss case)



Wind Potential (12% Losses)

32-37% Capacity Factor: 14,000 MW
37-41% Capacity Factor: 1,000 MW
41-46% Capacity Factor: 100 MW
>46% Capacity Factor: <100 MW

Total: 15,000 MW



Wind Potential (12% Losses)

32-37% Capacity Factor: 214,000 MW
37-41% Capacity Factor: 38,000 MW
41-46% Capacity Factor: 2,000 MW
>46% Capacity Factor: <100 MW

Total: 254,000 MW

Michigan Wind Electric Potential (Installed Capacity)

We calculated a range of wind speeds and net capacity factors, assuming power losses of 12%, comparable to wind power classes 4 to 7. The wind speed ranges were used to estimate the windy land area and wind potential at map height of 70m and 100m.

Wind potential was estimated assuming 5 MW of installed wind capacity per square kilometer of available windy land. Capacity factors were based on the GE 1.5 MW 77-m turbine.

12% Power Losses

Net Capacity Factor (%)	Speed m/s	50-m Class (equivalent)
32 – 37	7.2 – 7.69	Class 4
37 – 41	7.7 – 8.29	Class 5
41 – 46	8.3 – 9.19	Class 6
> 46	>= 9.2	Class 7

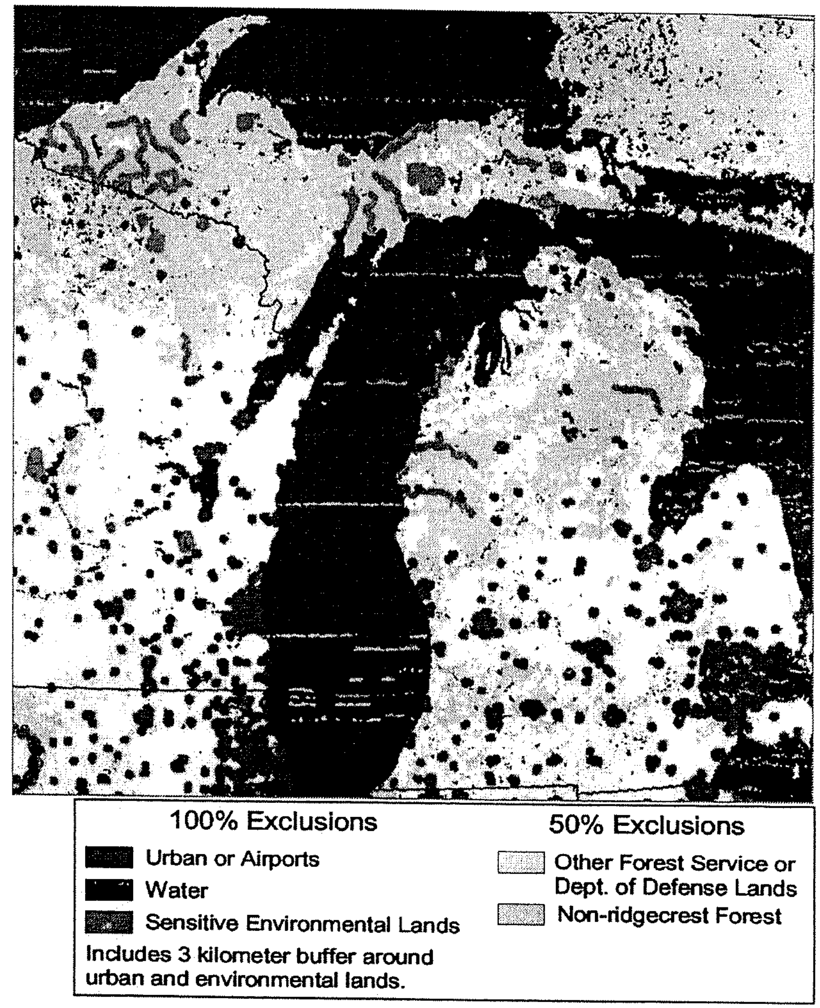
Estimates of Michigan Wind Electric Potential (Installed Capacity)

Assumes **12% Power Losses**

	70-m Height	**100-m Height**
Class 4	14,000 MW	214,000 MW
Class 5	1,000 MW	38,000 MW
Class 6	100 MW	2,000 MW
Class 7	<100 MW	<100 MW
Total	**15,000 MW**	**254,000 MW**

Areas Excluded from Developable Wind Potential

1) Potentially sensitive environmental lands:
   - National Park Service and Fish and Wildlife Service
   - Wildlife, wilderness, recreation areas, and other specially designated areas on federal land (predominantly Forest Service and BLM lands)
   - Some state and private environmental lands where data was available
   - Half of the remaining U.S. Forest Service and Department of Defense lands to represent current dedicated use of land
2) Potentially incompatible land use:
   - Urban areas, airports, wetlands and water bodies
   - Half of non-ridge crest forested areas
3) Other factors:
   - Slopes greater than 20%
   - A 3 kilometer area surrounding environmental and land use excluded areas (except water bodies)
   - Small, isolated class 3 and greater resource areas using a minimum density criteria



42% of the raw Class 4 and better lands excluded at 70 m (12% loss case)
31% of the raw Class 4 and better lands excluded at 100 m (12% loss case)

Fine-Turning Michigan Wind Potential Analysis

- 50 m analysis in 2004 used wind power class and exclusions to calculate potential
- Analysis of 70 m and 100 m wind potential in 2006 used: Wind speeds combined with capacity factor derived from commercial turbine
- Wind speed maps at 70 m and 100 m unchanged from original 2004 values
- Need much more tall tower data across the region to validate 70 m and 100 m speeds and confidently modify speed maps

NREL Needs More Michigan Data

- Anyone with accurate wind data from Michigan at tower heights of 30m and above is encouraged to contact NREL to discuss sharing the data.
- NREL can keep confidential its data sources and specific tower locations
- Contact George Scott at NREL to discuss: george_scott@nrel.gov, 303-384-6903

NREL Contact Information

- George Scott: george_scott@nrel.gov, 303-384-6903
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Attachment 2

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EXECUTIVE DIRECTIVE NO. 2005-4

ENERGY EFFICIENCY IN STATE FACILITIES AND OPERATIONS

WHEREAS, Section 1 of Article V of the Michigan Constitution of 1963 vests the executive power of the State of Michigan in the Governor;

WHEREAS, under Section 8 of Article V of the Michigan Constitution of 1963 each principal department of state government is under the supervision of the Governor unless otherwise provided by the Constitution;

WHEREAS, under Section 8 of Article V of the Michigan Constitution of 1963, the Governor is responsible to take care that the laws be faithfully executed;

WHEREAS, under Executive Order 2002-20, MCL 18.321, all of the authority, powers, functions, duties, and responsibilities pertaining to the planning, management and operation, capital renewal, and acquisition of buildings and facilities of Executive Branch agencies, excluding the Department of Transportation, the Department of Military and Veterans Affairs and the Department of Natural Resources, were transferred to the Department of Management and Budget;

WHEREAS, under Section 551 of The Management and Budget Act, 1984 PA 431, MCL 18.1551, the Governor shall inquire into the administration of The Management and Budget Act;

WHEREAS, under Section 261 of The Management and Budget Act, 1984 PA 431, MCL 18.1261, the Department of Management and Budget must provide for the purchase of, the contracting for, and the providing of supplies, materials, services, insurance, utilities, third party financing, equipment, printing, and all other items as needed by state agencies for which the Legislature has not otherwise expressly provided;

WHEREAS, under Section 241b of The Management and Budget Act, 1984 PA 431, MCL 18.1241b, the Department of Management and Budget must consider the energy efficiency of all materials used in the construction, alteration, repair, or rebuilding of a building or facility owned or operated by this state;

WHEREAS, under Section 253 of The Management and Budget Act, 1984 PA 431, MCL 18.1253, a state agency may enter into a multi-year contract for energy conservation improvements to state facilities to be paid for from the avoided operating costs for utility service or fuel produced by the improvements;

WHEREAS, under Section 213 of The Management and Budget Act, 1984 PA 431, MCL 18.1213, the Department of Management and Budget may issue directives relative to motor vehicles used by all state agencies, except for motor vehicles under the jurisdiction of the Department of Transportation;

WHEREAS, under Section 131 of The Management and Budget Act, 1984 PA 431, MCL 18.1131, the Director of the Department of Management and Budget may issue, alter, or rescind administrative and procedural directives as determined to be necessary for the effective administration of the Act;

WHEREAS the State of Michigan, in the operation of state facilities and use of state motor vehicles, consumes significant amounts of electricity, natural gas, petroleum, fuel oil, chilled water, steam, gasoline, and other natural resources;

WHEREAS, the cost of energy continues to rise and traditional sources of non-renewable energy continue to be depleted at a rapid pace;

WHEREAS, the State of Michigan is a leading consumer of energy throughout Michigan;

WHEREAS, products or processes that use less energy provide both an environmental and a fiscal benefit;

WHEREAS, state departments and agencies will benefit from interagency communication and joint problem solving to reduce energy consumption and achieve new energy efficiencies;

WHEREAS, dramatic increases in energy prices have increased the importance of reducing energy costs incurred by state government and protecting Michigan's economy through increased energy efficiency;

WHEREAS, Michigan taxpayers will benefit from the cost savings delivered and an improved environment with less pollution through greater energy efficiency;

NOW, THEREFORE, I, Jennifer M. Granholm, Governor of the State of Michigan, by virtue of the power vested in the Governor by the Michigan Constitution of 1963 and Michigan law direct the following:

I. DEFINITIONS

As used in this Directive:

A. "Alternative Fuel" includes a "clean fuel" as defined under Section 2 of the Michigan Next Energy Authority Act, 2002 PA 593, MCL 207.822.

B. "Department" means the Department of Management and Budget, a principal department of state government established under Section 121 of The Management and Budget Act, 1984 PA 431, MCL 18.1121.

C. "Energy Conservation Measure" means improvement of a building structurally or the installation of equipment or materials in a building for the purpose of reducing energy consumption or cost, increasing energy efficiency, or allowing the use of a renewable resource for fuel.

D. "Energy Star" means the voluntary partnership among the United States Department of Energy, the United States Environmental Protection Agency, product manufacturers, local utilities, and retailers to help promote energy efficient products by labeling with the Energy Star® logo, educate consumers about the benefits of energy efficiency, and help promote energy efficiency in buildings by benchmarking and rating energy performance.

E. "Hybrid Vehicle" includes a "hybrid vehicle" or a "hybrid electric vehicle" as defined under Section 2 of the Michigan Next Energy Authority Act, 2002 PA 593, MCL 207.822.

F. "LEED" means the Leadership in Energy and Environmental Design Green Building Rating System developed by the United States Green Building Council. LEED is recognized as the nation's leading green building rating system and promotes high-performance building practices; energy, water, and materials conservation; environmentally preferred products and practices; improvements in employee health, comfort, and productivity; and reductions in facility operation costs and environmental impacts.

II. REDUCING ENERGY USE IN STATE BUILDINGS

A. The Department of Management and Budget shall establish an energy efficiency savings target for all state buildings managed by the Department or another department or agency within the Executive Branch of state government. The goal shall be to attain a 10% reduction in energy use by December 31, 2008 and a 20% reduction in grid-based energy purchases by December 31, 2015, when compared to energy use and energy purchases for the state fiscal year ending September 30, 2002.

B. On or before December 31, 2006, the Department shall implement Energy Conservation Measures and the following best management practices to improve energy efficiency:

1. Establish a program for an energy analysis of each state building identifying opportunities for reduced energy use, the cost, and associated savings for each, including a completion schedule for the energy analysis program. Under the program, the Energy Star assessment and rating program shall be extended to all state buildings occupied by state employees.

2. Establish a program to perform regular maintenance on all lighting, heating, ventilation, and air conditioning systems, including, but not limited to, lubricating, balancing, aligning, vacuuming, cleaning, and checking seals, to ensure optimum efficiency.

3. Establish a program to evaluate the feasibility of converting to more energy-efficient lighting systems, including goals for making cost-effective lighting efficiency improvements that reduce electricity costs and maintain illumination quality.

4. Establish policies and procedures to identify and eliminate air infiltration and improve thermal insulation in building exteriors, such as walls, windows, doors, ceilings and floors.

5. Establish policies and procedures to reduce unnecessary use of lighting, heating, ventilation, and air conditioning systems, and to control thermostats to maximize energy savings while also providing occupant comfort.

6. Establish policies and procedures to maintain, monitor, and control systems that use water to reduce waste.

7. Establish policies and procedures to ensure the energy-saving feature in all Energy Star compliant electronic office equipment is activated, unless enabling the feature will hinder the performance or security of the equipment.

C. The Department shall explore and identify options for funding these energy initiatives, including, but not limited to, federal funds and grants and the use of energy conservation work orders or work projects as authorized under Section 254 of The Management and Budget Act, 1984 PA 431, MCL 18.1254.

III. ENERGY EFFICIENCY AND THE STATE MOTOR VEHICLE FLEET

A. In managing the State of Michigan's reduced fleet of motor vehicles, the Department shall do all of the following:

1. Comply with the requirements of the federal Energy Policy Act of 1992, as amended, (EPAct) which is intended to reduce the United States' dependence on foreign oil by requiring certain fleets, including motor vehicle fleets operated by state governments, to acquire Alternative Fuel vehicles capable of operating on non-petroleum fuels or on blended fuels with lower petroleum content.

2. Include Hybrid Vehicles within the state's fleet, if analysis by the department determines the Hybrid Vehicles to be cost effective and capable of meeting the state's transportation needs.

3. As the public Alternative Fuel infrastructure continues to develop, require the users of motor vehicles within the state fleet to refuel with Alternative Fuels to the extent feasible. Where Alternative Fuel is available and cost-effective, require users of motor vehicles within the state fleet to purchase Alternative Fuel.

4. Develop procedures to encourage or require the use of diesel fuel with the highest percentage of biodiesel content available, when biodiesel fuel is available to a user of a diesel fuel vehicle in the state fleet.

IV. ENERGY EFFICIENCY AND STATE PURCHASING

A. The Department shall revise state purchasing policies and procedures to do all of the following:

1. Include energy efficiency considerations and life-cycle costs when determining whether the purchase of or contracting for goods or supplies represents the best value for the State of Michigan, including, but not limited to, equipment purchased for state facilities such as lighting equipment, heating systems, ventilation systems, air conditioning systems, and water heating systems. As used in this paragragh, "life-cycle costs" means the purchase price for goods or supplies plus the estimated operating costs for the goods or supplies over the useful life of the goods or supplies.

2. Specify that any of the following purchased by state departments or agencies shall be Energy Star compliant:

a. New electronic office equipment purchased by state departments or agencies shall be Energy Star compliant to the extent Energy Star certified equipment is available.

b. Major appliances purchased for state-owned or operated facilities, including residential facilities, shall be Energy Star compliant to the extent Energy Star certified equipment is available.

V. ENERGY EFFICIENCY AND STATE CAPITAL OUTLAY PROJECTS

A. Currently all state-supported capital outlay projects over $1 million, whether for state departments or agencies, universities, or community colleges, must be designed and constructed in accordance with the Leadership in Energy and Environmental Design (LEED) Green Building Rating System developed by the United States Green Building Council. LEED certification ensures that all new state facilities are energy efficient and environmentally sustainable.

B. The Department shall adopt policies and procedures to ensure that all new construction and major renovation of state-owned facilities, including all capital outlay projects, shall be accomplished consistent with LEED guidelines and standards, and shall score a minimum of 26 points on the LEED scorecard established by the United States Green Building Council, which is the minimum score required for LEED-certified status. The policies and procedures required under this paragraph shall apply to state-leased facilities to the extent feasible.

VI. RECOGNITION OF EFFORTS TO IMPROVE STATE ENERGY EFFICIENCY

A. The Department shall establish an annual award program to be known as the Governor's Award for Excellence in Energy Efficiency to annually recognize and reward state department or agency progress in implementing cost-effective energy efficiency and Energy Conservation Measures and for achieving energy savings.

VII. IMPLEMENTATION AND ENFORCEMENT

A. The Department, the Department of Labor and Economic Growth, the Department of Environmental Quality, the Department of Agriculture, and the Michigan Public Service Commission shall provide technical assistance to state departments and agencies in implementing this Directive.

B. On or before June 30, 2005, the Directors of the Department of Environmental Quality, the Department of Labor and Economic Growth, and the Department shall make recommendations to the Governor identifying additional opportunities to promote greater energy efficiency and expanded use of clean technology in Michigan.

C. The Department shall adopt policies and procedures to require all state departments to prepare an annual report describing steps taken to incorporate energy efficiency into operations. Beginning November 30, 2006, the Department shall prepare an annual report on the state's progress in employing strategies to improve energy efficiency, implementation of Energy Conservation Measures and savings achieved.

D. The Department shall enforce the requirements of this Directive and any policies, procedures, or department directives issued to implement this Directive pursuant to The Management and Budget Act, 1984 PA 431, MCL 18.1101 to 18.1594.

E. Reports of violation of the requirements of this Directive shall be transmitted to the Director of the Department.
All departments and agencies shall assist the Department, as necessary, in implementing this Directive

This directive is effective April 22, 2005.

Given under my hand this 21st day of April, in the year of our Lord, two thousand and five.

JENNIFER M. GRANHOLM
GOVERNOR

Attachment 3

Response to Senator Kuipers question. MLC 5-2-07

DTE's annual rate changes during the past three years.

Line	Description:	January 2004	January 2005	January 2006	January 2007
1	Residential @ 500 kWh (Rate D1)	$43.44	$43.44	$48.81	$52.51
2	Rate per kWh	$0.0869	$0.0869	$0.0976	$0.1050
3	Percent Change from Prior Year		0.0%	12.4%	7.6%
4					
5					
6	Small Commercial @ 1,000 kWh (Rate D3)	$103.09	$109.81	$106.24	$112.06
7	Rate per kWh	$0.1031	$0.1098	$0.1062	$0.1121
8	Percent Change from Prior Year		6.5%	-3.3%	5.5%
9					
10					
11	Large Commercial @ 36,000 kWh (Rate D4)	$3,447.91	$3,500.89	$3,388.67	$3,612.04
12	Rate per kWh	$0.0958	$0.0972	$0.0941	$0.1003
13	Percent Change from Prior Year		1.5%	-3.2%	6.6%
14					
15					
16	Large Industrial @ 4,320,000 kWh (Rate D6)	$269,638.07	$275,002.23	$289,246.19	$317,019.42
17	Rate per kWh	$0.0624	$0.0637	$0.0670	$0.0670
18	Percent Change from Prior Year		2.0%	5.2%	9.6%

Notes:

PA 141 of 2000 froze residential rates until January 2006, and small commercial & industrial rates until January 2005.
PSCR costs for the Large Industrial customer increased $35,900 from 2006 to 2007, while the net rate increase was $27,773
Without an increase in the Power Supply Cost Recovery overall rates would have decreased in 2006.